PSD PERMIT APPLICATION
PUGET SOUND ENERGY
FREDONIA GENERATING STATION
EXPANSION PROJECT
MOUNT VERNON, WASHINGTON

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List of Acronyms

°F	degrees Fahrenheit
$\mu g/m^3$	micrograms per cubic meter
AAQS	ambient air quality standards
ALW	Alpine Lakes Wilderness
AOP	air operating permit
AQRV	air quality related values
ASIL	acceptable source impact level
BAAQMD	Bay Area Air Quality Management District
BACT	best available control technology
BART	best available retrofit technology
bhp	brake-horsepower
bkW	brake-kilowatt
BPIP-Prime	Building Parameter Input Program – Prime
CAA	Clean Air Act
CAAA	Clean Air Act Amendments
CARB	California Air Resources Board
CATEF	California air toxic emission factors
CEC	California Energy Commission
CEMS	continuous emissions monitoring system
CFR	code of federal regulation
CH_4	methane
CI	compression ignition
CO	carbon monoxide
CO_2	carbon dioxide
CO_2e	carbon dioxide equivalents
DAT	deposition analysis threshold
DC	direct current
DCS	distributed control system
DEM	digital elevation model
dscf	dry standard cubic foot
EC	elemental carbon
EPA	United States Environmental Protection Agency
EPS	emission performance standard
ESP	electrostatic precipitator
FGS	Fredonia Generating Station
FLAG	Federal Land Managers' Air Quality Related Values Workgroup
FLM	Federal Land Manager
FR	Federal Register
FWS	United States Fish and Wildlife Service
GE	General Electric
GHG	greenhouse gas
GPW	Glacier Peak Wilderness
gr	grains

GWP	global warming potential
H_2SO_4	sulfuric acid
HAP	hazardous air pollutant
HHV	higher heating value
HNO_3	nitric acid
IC	internal combustion
IWAQM	Interagency Workgroup on Air Quality Modeling
kg/ha-yr	kilogram per hectare per year
km	kilometers
kV	kilovolt
kW	kilowatt
LAC	level of acceptable change
LAER	lowest achievable emission rate
lb	pound
LCC	Lambert Conformal Conic
LHV	lower heating value
MSL	mean sea level
MTB	Mt. Baker Wilderness Area
MW	megawatt
MW-hr	Megawatt-hour
N	total nitrogen
N_2O	nitrous oxide
NAAQS	national ambient air quality standards
NCNP	North Cascades National Park
NH_3	ammonia
NH_4NO_3	ammonium nitrate
$(NH_4)_2SO_4$	ammonium sulfate
NO_2	nitrogen dioxide
NO_3	nitrate
NOC	Notice of Construction
NO_x	nitrogen oxides
NPS	National Park Service
NSCR	non-selective catalytic reduction
NSPS	new source performance standard
NSR	new source review
NWCAA	Northwest Clean Air Agency
O_2	oxygen
O_3	ozone
OC	organic carbon
ODEQ	Oregon Department of Environmental Quality
ONP	Olympic National Park
Pb	lead
PM	particulate matter
PM_{10}	particulate matter less than 10 μm in diameter
$PM_{2.5}$	particulate matter less than 2.5 μm in diameter

PMC	coarse particulate matter (PM_{10})
PMF	fine particulate matter ($PM_{2.5}$)
PMS	particulate matter speciation
ppb	parts per billion
ppm	parts per million
ppmvd	parts per million by volume dry
PSD	prevention of significant deterioration
PSE	Puget Sound Energy
Q/d	ratio of emissions to distance
RBLC	RACT/BACT/LAER Clearinghouse
RH	relative humidity
S	total sulfur
SCAQMD	South Coast Air Quality Management District
scf	standard cubic foot
SCR	selective catalytic reduction
SER	significant emission rate
SF_6	sulfur hexafluoride
SIL	significant impact level
SJVAPCD	San Joaquin Valley Air Pollution Control District
SNCR	selective non-catalytic reduction
SO_2	sulfur dioxide
SO_3	sulfur trioxide
SO_4	sulfate
SOA	organic compound (in modeling files)
SO_x	sulfur oxides
SQER	small quantity emission rate
TAP	toxic air pollutant
tBACT	toxics-BACT
tpy	tons per year
TSP	total suspended particulate
ULSD	Ultra-low sulfur distillate
USFS	United States Forest Service
USGS	United States Geological Survey
UTM	universal transverse mercator
UW	University of Washington
VAC	voltage alternating current
VDC	voltage direct current
VOC	volatile organic compounds
WAC	Washington Administrative Code

1.1 BACKGROUND

Puget Sound Energy (PSE) owns and operates the Fredonia Generating Station (FGS) at 13085 Ball Road, near Mount Vernon, Washington. The current site is approximately 40 acres and is located approximately five miles northwest of the town of Mount Vernon, and south of Skagit Regional Airport. The existing FGS facility consists of two Westinghouse W501D simple cycle combustion generators, and two Pratt & Whitney Model FT-8 Twin Pac simple cycle turbines. All four turbines are permitted to use either natural gas or distillate fuel. Natural gas is normally used; distillate fuel is infrequently used as a backup fuel. The Westinghouse turbines (Units 1 and 2) have a base load rating of 104 megawatts (MW) each, and the Pratt & Whitney turbines (Units 3 and 4) have a base load rating of 54 MW each.

The proposed Fredonia Generating Station Expansion Project (Project) is a simple cycle electric generating unit addition to the existing FGS. The Project will consist of one or two additional gas combustion turbines totaling approximately 181-207 MW. The Project base design will consist of one of the following simple cycle turbine options:

- One General Electric (GE) 7FA.05 frame turbine, approximately 207 MW;
- One GE 7FA.04 frame turbine, approximately 181 MW;
- One Siemens SGT6-5000F4 frame turbine, approximately 197 MW; or
- Two 100 MW GE LMS100 high-efficiency aeroderivative turbines, totaling approximately 200 MW.

PSE requests permission to construct any one of these options, and to choose that option at a later date after permit issuance.

The purpose of the new generating unit(s) will be to provide additional power generation capacity to help meet future PSE system needs using locally available fuels. The Expansion Project must be capable of starting up and shutting down relatively quickly to meet sudden changes in system power demands. No physical change or changes in method of operation will occur to the exiting Fredonia Generating Station units. They will continue to respond to short-term system capacity requirements as they currently do.

Turbine selection for the Project will be made on the basis of a commercial and technical evaluation by PSE after further engineering and procurement efforts, possibly after air permits are issued. The selected equipment's thermodynamic and environmental performance will meet or exceed the performance of the turbines analyzed for the permit application. The plant's primary fuel will be natural gas delivered to the site by the adjacent transmission pipeline owned by Cascade Natural Gas. Ultra-low sulfur (0.0015% sulfur) No. 2 distillate (ULSD) is planned as backup fuel, stored onsite in an existing 100,000 barrel tank. Back-up fuel oil will be needed to continue serving PSE's electrical load when natural gas supply is curtailed by the pipeline supply company or not reasonably available to be received at the facility. Historically, this has happened but is a rare occurrence. PSE anticipates that operation of the new unit(s) on ULSD will occur no more than 336 hours per year. During most years, ULSD firing is expected to be much less. PSE proposes to interconnect the new unit(s) to the adjacent FGS substation, which is the nearest connection point to PSE's electrical grid.

The Project also includes a diesel standby generator (Caterpillar C18, or equivalent) for emergency use whenever connection to the regional power grid is lost. Its purpose is to supply power to the turbine(s) battery bank which keeps turbine ancillaries (such as a lube oil pump) energized in order to protect this and other equipment and electrical systems at the facility. It will also be operated briefly for periodic maintenance and testing.

1.2 APPLICATION OVERVIEW

The existing facility is a major Prevention of Significant Deterioration (PSD) stationary source per Title 40 of the Code of Federal Regulations (CFR) Section 52.21(b)(1)(i), and operates under PSD Permit PSD-01-04, issued on July 29th, 2003, and Northwest Clean Air Agency (NWCAA) Air Operating Permit (AOP) 003-R1, issued March 7, 2005. The proposed Project is expected to be a major modification under PSD (per 40 CFR 52.21(b)(40)). See Section 4.1 for details. Washington State Department of Ecology (Ecology) is the permitting lead for PSD, with concurrence from United States Environmental Protection Agency (EPA) and the regional agency, NWCAA. Concurrently, NWCAA will conduct a separate Notice of Construction (NOC) review and issue an Order of Approval for the proposed Project. At present, the Project region is attainment for all criteria air pollutants. It is anticipated that this Project will be permitted prior to area redesignation, if it occurs, in response to the EPA's proposed revised 1-hour ozone standard, which has not been adopted as of the date of this application.

This application package has been designed to respond to the requirements of PSD (EPA/Ecology) and NOC (NWCAA); the application incorporates agency guidance received during a preapplication meeting with Ecology and NWCAA on June 16, 2010, and subsequent modeling guidance from Ecology, EPA, and the Federal Land Manager (FLM). Additionally, several comments received on the initial submittal from February 2011 have been addressed following discussions with Ecology and NWCAA (at a meeting on April 19, 2011, and in email correspondence in April and May 2011). Concurrent with the submittal of this air quality application, other required environmental permits and approvals are being pursued with the appropriate regulatory agencies.

This section (Section 1) contains introductory information. Section 2 presents a description of the facility and its processes. The estimated emissions of regulated pollutants from these processes and operating scenarios are presented in Section 3. Section 4 is a general assessment of regulatory requirements applicable to facility operations. The Best Available Control Technology (BACT) analysis is included in Section 5; this section also includes BACT for toxics (tBACT). An ambient air quality analysis, as required under PSD review, is presented in Section 6. The Air Quality Related Values (AQRV), including visibility and deposition, is provided in Section 7. Section 8 includes an analysis of hazardous and toxic air pollutants, and Section 9 provides greenhouse gas (GHG) compliance information. Detailed emissions data are provided in Attachment A. Attachment B contains the modeling protocol (and amendments), which have already been reviewed by Ecology, EPA, NWCAA, and the FLM. The ambient air quality impact modeling files are provided in Attachment C. Attachment D provides the AQRV modeling analyses for Class I areas and the Class II Mt. Baker Wilderness Area (MTB). The non-criteria pollutant (hazardous/toxic air pollutant) analysis details (emissions and modeled impacts, where applicable) are provided in Attachment E. Greenhouse gas mitigation calculations are shown in Attachment F. Attachment G contains completed NWCAA NOC application form for the Project.

2.1 PROJECT LOCATION

The FGS facility is located at 13085 Ball Road near Mount Vernon, Skagit County, Washington (see Figure 2-1). The site is on south side of Ovenell Road, south of the west end of the Skagit Regional Bayview Airport, approximately 2.5 miles inland of Padilla Bay. The proposed Project is not expected to increase the current footprint acreage of the site, which is approximately 40 acres. The terrain surrounding the facility is essentially flat. The elevation of the facility is approximately 50 feet above mean sea level (MSL). There are no known sensitive receptors nearby to the facility.

2.1.1 Land Use

The region surrounding the PSE site is primarily industrial and agricultural, with several municipal and industrial facilities in the immediate vicinity, including the Skagit Regional Bayview Airport and the Paccar Technical Center, both north of the PSE facility, and multiple lumber conversion facilities to the south.

2.2 DESCRIPTION OF THE PROPOSED SOURCE MODIFICATION

As described above, the proposed Project involves the addition of one or two simple cycle electric generating unit(s) to the existing FGS. The Project base design will consist of one of the following simple cycle turbine options:

- One GE 7FA.05 frame turbine, approximately 207 MW;
- One GE 7FA.04 frame turbine, approximately 181 MW;
- One Siemens SGT6-5000F4 frame turbine, approximately 197 MW; or
- Two 100 MW GE LMS100 high-efficiency aeroderivative turbines, totaling approximately 200 MW.

This permit application, including modeling analysis, addresses each of these options. Final turbine selection will be made on the basis of a commercial and technical evaluation by PSE after further engineering and procurement efforts, possibly after air permits are issued. The selected equipment’s thermodynamic and environmental performance will meet or exceed the performance of the turbines analyzed for the permit application.

The primary fuel for the new unit(s) will be natural gas. Back-up fuel oil (ULSD) will be needed/used when natural gas is not reasonably available. The back-up fuel use is described further in Section 5 (BACT).

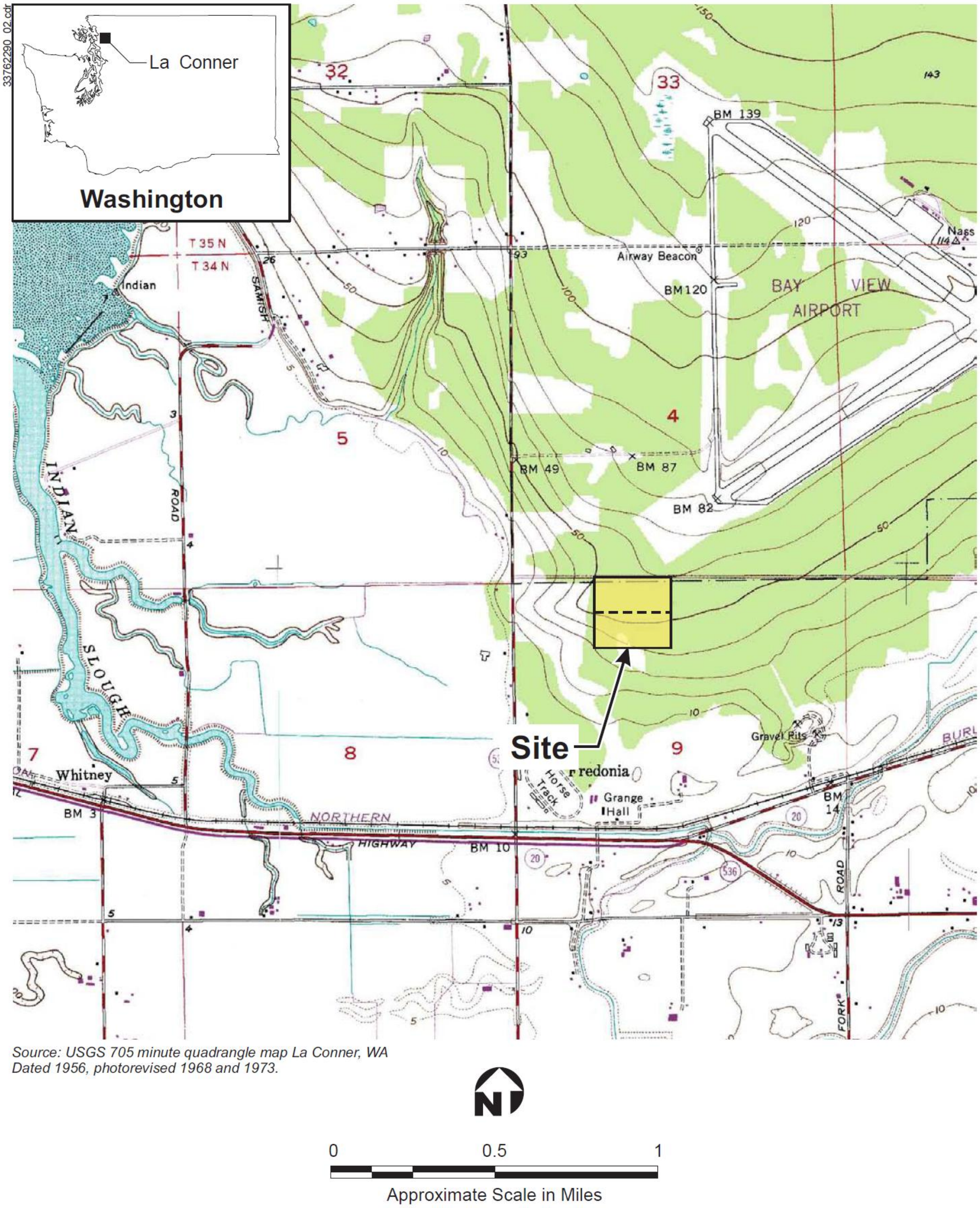
In addition to the turbine(s), the Project includes one nominal 600 kilowatt (kW) diesel standby generator (Caterpillar C18, or equivalent) to supply the new units’ critical electrical loads in the event power could not be back fed from either the site's 230 kilovolt (kV) or 115 kV transmission systems. The turbine(s) would be supplied with a 125 VDC (voltage direct current) battery bank to supply a critical 120 VAC (voltage alternating current) Essential Power Bus through an inverter or directly from a 125 VDC Essential Power Bus. Examples of devices needing Essential Power from one or both of these sources would be the facility's Distributed Control System (DCS), protective relays and a direct current (DC) driven emergency lube oil pump. In the event of a transmission system failure and blackout of the facility, the 125 VDC and 120 VAC Essential Power Buses could be kept energized for a period of time from the 125 VDC battery bank. However, the turbine units have the potential to expend the battery's power quickly since they have large, heavy components, such as rotor bearings, that need large electrically driven lubricating pumps. To prevent damage to these components during a transmission system failure, an emergency generator is needed to provide power to back up the batteries. Testing and maintenance operations for the emergency generator are expected to occur 1 hour per week, or 52 hours per year.

The Project's proposed new 230 kV switchyard will include eight new circuit breakers filled with sodium hexafluoride (SF_6), a gaseous dielectric commonly used in breakers. In addition to these eight breakers accommodating the new equipment, there will also be two other new breakers installed to replace some existing units. A small amount of the GHG pollutant SF_6 is emitted from switchyard breakers as a result of unavoidable leakage. Therefore, these 10 breakers are included in this application due to their predicted GHG emissions. Although specific models have not been identified, PSE expects that Mitsubishi 200-SFMT-40E or 200-SFMT-63F breakers (or similar) will be used.

A conceptual plot plan for the GE 7FA.05 or GE 7FA.04 unit is presented in Figure 2-2; for the Siemens SGT6-5000F4 unit in Figure 2-3; and for the GE LMS100 two-turbine option in Figure 2-4. (Note: larger scale versions of these figures are included with Attachment C-2.)

2.3 PSD APPLICABILITY

The existing facility is a PSD major source. The proposed Project is considered a major modification to the existing source, thereby triggering this PSD process. Details regarding regulatory applicability are provided in Section 4 of this application, and specific emissions related to this evaluation are given in Section 3.1.



Source: USGS 705 minute quadrangle map La Conner, WA
Dated 1956, photorevised 1968 and 1973.

Figure 2-1 – General Location Map

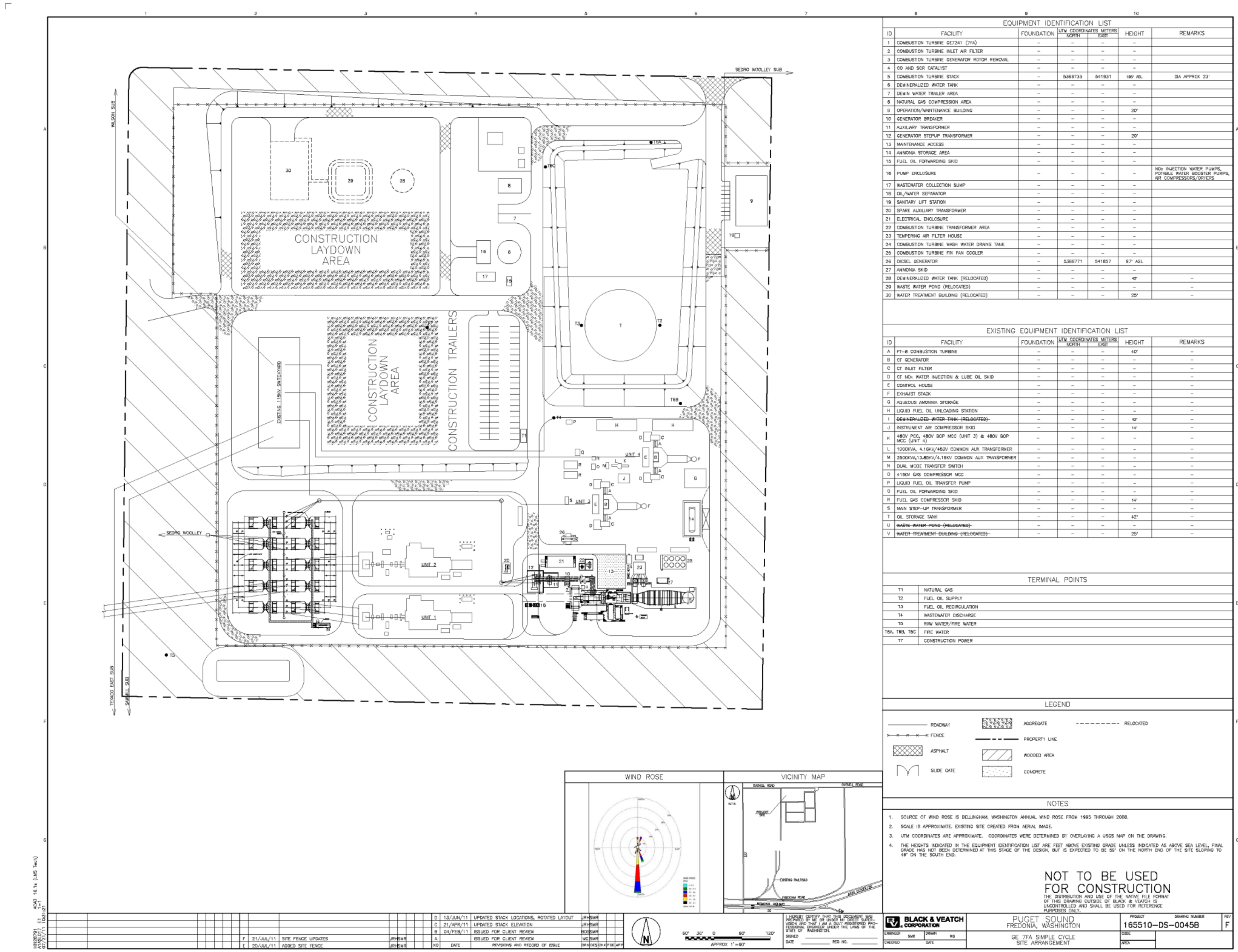


Figure 2-2 – Conceptual Turbine Site Layout for the GE 7FA.05 and GE 7FA.04

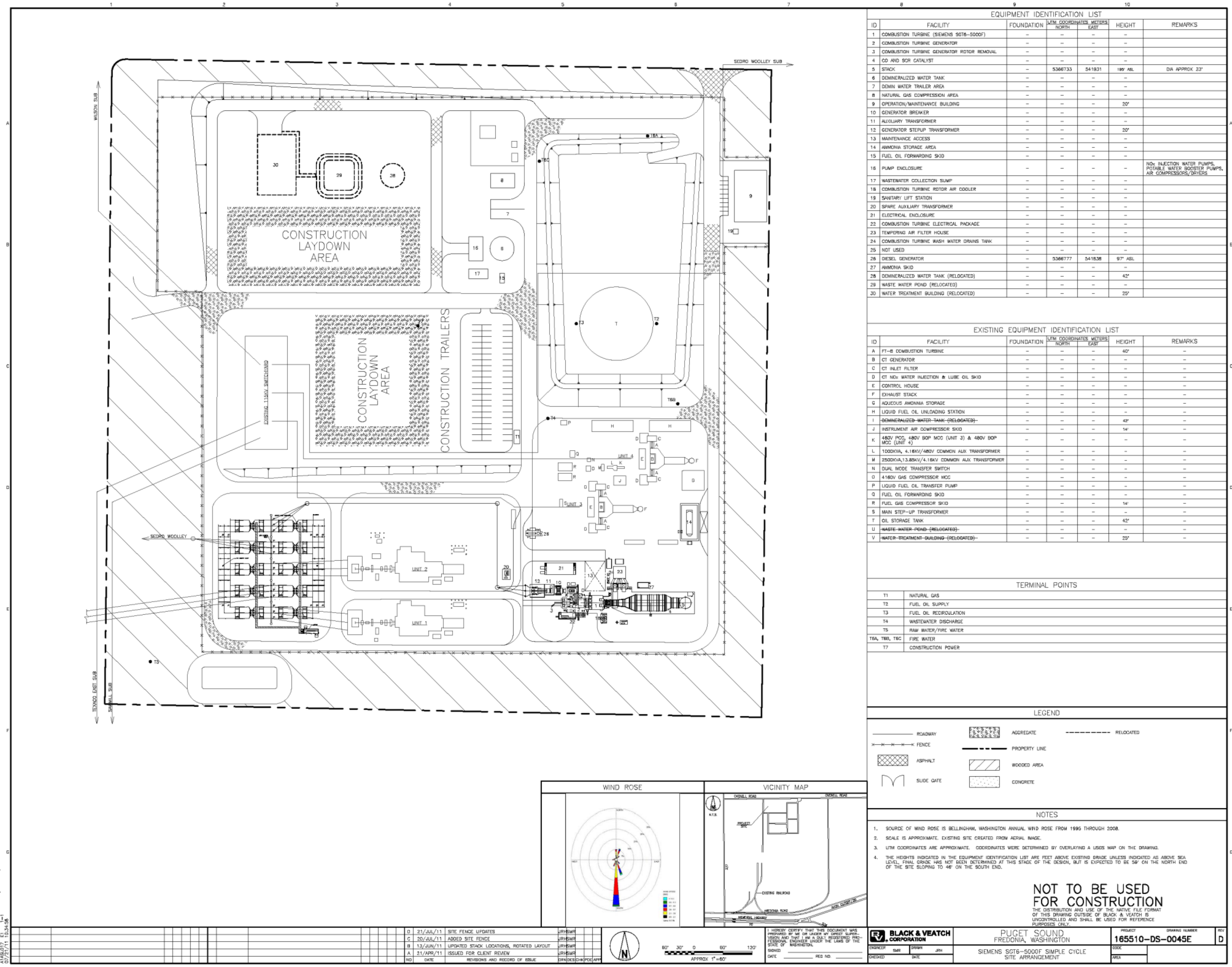
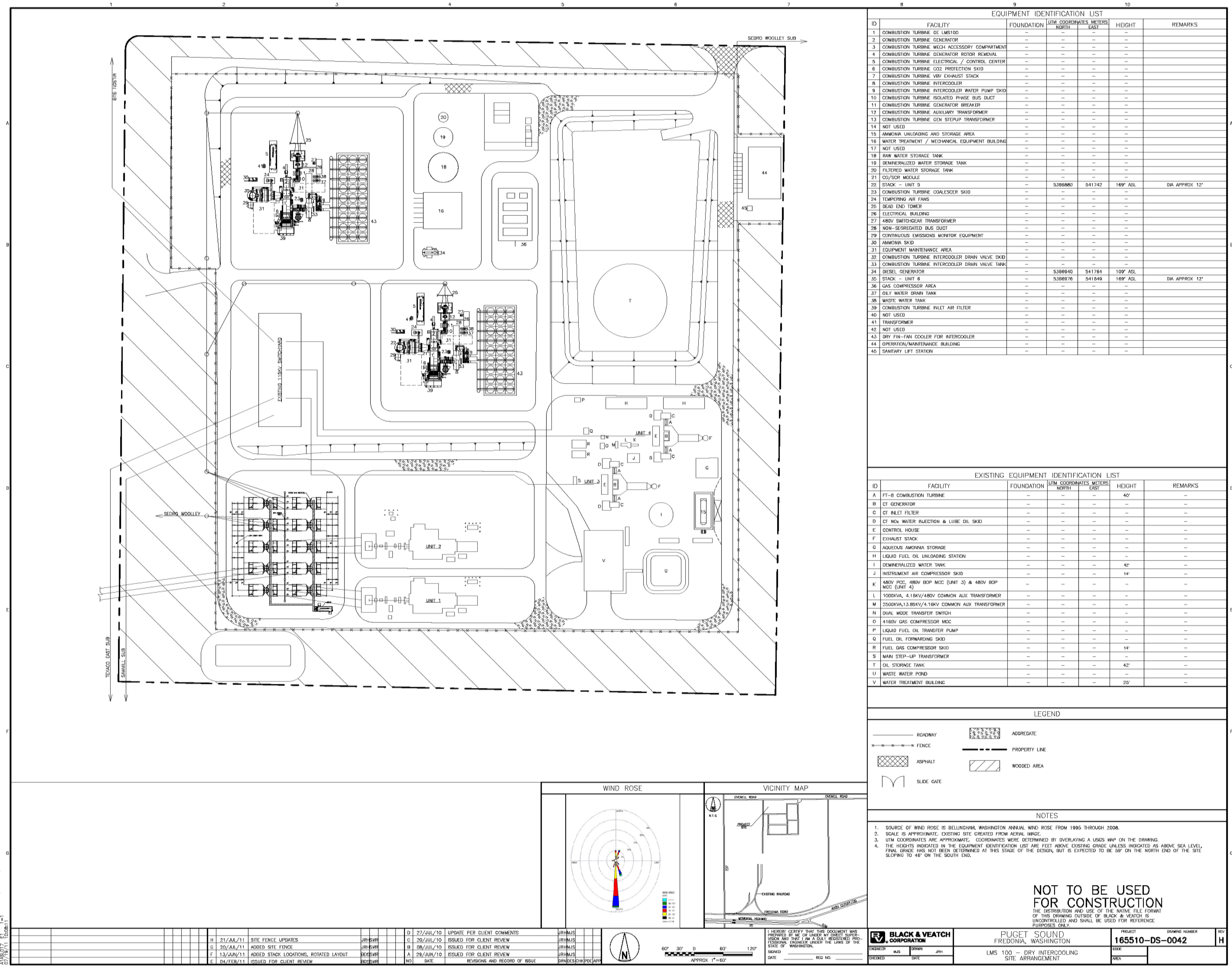


Figure 2-3 – Conceptual Turbine Site Layout for the Siemens SGT6-5000F4



EQUIPMENT IDENTIFICATION LIST

ID	FACILITY	FOUNDATION	UTM COORDINATES METERS NORTH	UTM COORDINATES METERS EAST	HEIGHT	REMARKS
1	COMBUSTION TURBINE GE LMS100	–	–	–	–	
2	COMBUSTION TURBINE GENERATOR	–	–	–	–	
3	COMBUSTION TURBINE MECH ACCESSORY COMPARTMENT	–	–	–	–	
4	COMBUSTION TURBINE GENERATOR ROTOR REMOVAL	–	–	–	–	
5	COMBUSTION TURBINE ELECTRICAL / CONTROL CENTER	–	–	–	–	
6	COMBUSTION TURBINE CO2 PROTECTION SKID	–	–	–	–	
7	COMBUSTION TURBINE VBV EXHAUST STACK	–	–	–	–	
8	COMBUSTION TURBINE INTERCOOLER	–	–	–	–	
9	COMBUSTION TURBINE INTERCOOLER WATER PUMP SKID	–	–	–	–	
10	COMBUSTION TURBINE ISOLATED PHASE BUS DUCT	–	–	–	–	
11	COMBUSTION TURBINE GENERATOR BREAKER	–	–	–	–	
12	COMBUSTION TURBINE AUXILIARY TRANSFORMER	–	–	–	–	
13	COMBUSTION TURBINE GEN STEPUP TRANSFORMER	–	–	–	–	
14	NOT USED	–	–	–	–	
15	AMMONIA UNLOADING AND STORAGE AREA	–	–	–	–	
16	WATER TREATMENT / MECHANICAL EQUIPMENT BUILDING	–	–	–	–	
17	NOT USED	–	–	–	–	
18	RAW WATER STORAGE TANK	–	–	–	–	
19	DEMINERALIZED WATER STORAGE TANK	–	–	–	–	
20	FILTERED WATER STORAGE TANK	–	–	–	–	
21	CO/SCR MODULE	–	–	–	–	
22	STACK – UNIT 5	–	5366880	541742	169' ASL	DIA APPROX 12'
23	COMBUSTION TURBINE COALESCER SKID	–	–	–	–	
24	TEMPERING AIR FANS	–	–	–	–	
25	DEAD END TOWER	–	–	–	–	
26	ELECTRICAL BUILDING	–	–	–	–	
27	480V SWITCHGEAR TRANSFORMER	–	–	–	–	
28	NON–SEGREGATED BUS DUCT	–	–	–	–	
29	CONTINUOUS EMISSIONS MONITOR EQUIPMENT	–	–	–	–	
30	AMMONIA SKID	–	–	–	–	
31	EQUIPMENT MAINTENANCE AREA	–	–	–	–	
32	COMBUSTION TURBINE INTERCOOLER DRAIN VALVE SKID	–	–	–	–	
33	COMBUSTION TURBINE INTERCOOLER DRAIN VALVE TANK	–	–	–	–	
34	DIESEL GENERATOR	–	5366940	541764	109' ASL	
35	STACK – UNIT 6	–	5366976	541649	169' ASL	DIA APPROX 12'
36	GAS COMPRESSOR AREA	–	–	–	–	
37	OILY WATER DRAIN TANK	–	–	–	–	
38	WASTE WATER TANK	–	–	–	–	
39	COMBUSTION TURBINE INLET AIR FILTER	–	–	–	–	
40	NOT USED	–	–	–	–	
41	TRANSFORMER	–	–	–	–	
42	NOT USED	–	–	–	–	
43	DRY FIN–FAN COOLER FOR INTERCOOLER	–	–	–	–	
44	OPERATION/MAINTENANCE BUILDING	–	–	–	–	
45	SANITARY LIFT STATION	–	–	–	–	

EXISTING EQUIPMENT IDENTIFICATION LIST

ID	FACILITY	FOUNDATION	UTM COORDINATES METERS NORTH	UTM COORDINATES METERS EAST	HEIGHT	REMARKS
A	FT–8 COMBUSTION TURBINE	–	–	–	40'	–
B	CT GENERATOR	–	–	–	–	–
C	CT INLET FILTER	–	–	–	–	–
D	CT NOx WATER INJECTION & LUBE OIL SKID	–	–	–	–	–
E	CONTROL HOUSE	–	–	–	–	–
F	EXHAUST STACK	–	–	–	–	–
G	AQUEOUS AMONNIA STORAGE	–	–	–	–	–
H	LIQUID FUEL OIL UNLOADING STATION	–	–	–	–	–
I	DEMINERALIZED WATER TANK	–	–	–	42'	–
J	INSTRUMENT AIR COMPRESSOR SKID	–	–	–	14'	–
K	480V PCC, 480V BOP MCC (UNIT 3) & 480V BOP MCC (UNIT 4)	–	–	–	–	–
L	1000KVA, 4.16KV/480V COMMON AUX TRANSFORMER	–	–	–	–	–
M	2500KVA,13.85KV/4.16KV COMMON AUX TRANSFORMER	–	–	–	–	–
N	DUAL MODE TRANSFER SWITCH	–	–	–	–	–
O	4160V GAS COMPRESSOR MCC	–	–	–	–	–
P	LIQUID FUEL OIL TRANSFER PUMP	–	–	–	–	–
Q	FUEL OIL FORWARDING SKID	–	–	–	–	–
R	FUEL GAS COMPRESSOR SKID	–	–	–	14'	–
S	MAIN STEP–UP TRANSFORMER	–	–	–	–	–
T	OIL STORAGE TANK	–	–	–	42'	–
U	WASTE WATER POND	–	–	–	–	–
V	WATER TREATMENT BUILDING	–	–	–	25'	–

Figure 2-4 – Conceptual Turbine Site Layout for the GE LMS100

3.1 ESTIMATED EMISSIONS FOR APPLICABILITY ANALYSES

Potential annual emissions for the new units and auxiliary equipment are based on worst-case operating scenarios estimated by PSE, and were generated from forecast load requirements. Maximum annual operating hours for the Frame turbines (GE 7FA.05, GE 7FA.04, and Siemens SGT6-5000F4) are expected to be approximately 2400 hours per year. Maximum annual operating hours for the GE LMS100's are expected to be approximately 3200 hours per year (for each of the two units). A maximum of 336 hours (equivalent to 14 days) firing on distillate is included in the annual emission estimates. On a pollutant-by-pollutant basis, this worst-case maximum of 336 hours (consecutive or nonconsecutive) firing on backup ULSD is included in the annual emission estimates only if pollutant emissions on ULSD are higher than emissions on natural gas.

Nitrogen oxide (NO_x) and carbon monoxide (CO) emission estimates assume a combination of gas turbine combustion controls, selective catalytic reduction (SCR) and an oxidation catalyst to achieve 2.5 parts per million (ppm) NO_x under normal operating conditions. CO emissions with oxidation catalyst controls vary for the turbine options; preliminary data show a range of approximately 2-13 ppm CO under normal operating conditions. (Detailed information regarding control technology is provided in Section 5 of this application.) A worst-case maximum number of start-ups and shutdowns on both natural gas and ULSD are also included in the annual emission estimates. Table 3-1 summarizes potential annual emission estimates for the four turbine options. Detailed emission spreadsheets are included as Attachment A.

Emissions from the proposed new unit(s) are expected to exceed the PSD Significant Emission Rates (SER) for all Project development options for particulate matter (Total Suspended Particulate (TSP), particulate matter less than 10 microns in diameter (PM_{10}), and particulate matter less than 2.5 microns in diameter ($PM_{2.5}$)). Emissions are also expected to exceed the SER for CO only for the Siemens SGT6-5000F4 option. The Project requires air quality evaluations to show compliance with Ambient Air Quality Standards (AAQS) in accordance with Washington Administrative Code (WAC) rules for pollutants that exceed the SER. Applicable regulations and guidelines require that this application provide dispersion modeling to demonstrate compliance with applicable ambient air quality standards and PSD increments. These impact analyses have been performed for the worst-case turbine scenarios, which were determined for each turbine option, and for each pollutant and averaging period. The Project's estimated potential annual emissions for NO_x, volatile organic compounds (VOC), and sulfur dioxide (SO_2) will not exceed the SER for any turbine option, therefore, ambient air quality modeling is not required, and further emissions estimates are not provided for these pollutants. (Note: additional emission estimates for NO_x and SO_2 are included in the AQRV analysis, which is discussed in Sections 3.3 and 7 of this application.) In addition, there is no AAQS for sulfuric acid (H_2SO_4), therefore no impact analyses are performed for this pollutant, even though it exceeds the SER.

As stated above, the facility's circuit breakers will also have the potential to emit a very small amount of GHG (as SF_6). Circuit breakers do not emit SF_6 directly, but they do have the potential for minor leakage, or fugitive emissions. The rate of leakage is conservatively assumed to be 0.5 percent, based on estimates from PSE on previous equipment which showed lower rates. Use of SF_6 is based on equipment specifications. Because specific breakers have not yet been chosen for this Project, the equipment option with the highest volume of SF_6 has been assumed for the emission calculations. Emission calculation details are provided in Attachment

A-13. The breaker emissions are used in the GHG analyses, applying the 100-year SF_6 global warming potential (GWP) of 23,900 to convert SF_6 emissions to carbon dioxide equivalents (CO_2e). This conversion is also shown in Attachment A-13, and the breaker emissions are included in the CO_2e emission totals shown in Table 3-1 and in Attachment A-1.

Further details regarding PSD applicability are addressed in Section 4.1of this application.

Sulfur compound emission estimates in this application are based on natural gas sulfur measurements published by Williams for the Northwest Pipeline compressor station at Sumas, WA. Seven years of daily total sulfur measurements (June 1, 2002 through March 8, 2010) were analyzed. The maximum 365-day rolling average was 1.10 gr/100 dscf (June 2009). Because an upward trend was observed in data for 2009 and preceding years, PSE assumed a worst-case future concentration of 2.00 gr/100 dscf for the Williams Northwest Pipeline to achieve a margin of safety for the Project's emission compliance. On top of that, 0.25 gr/100 dscf was added to account for worst-case odorant addition by Cascade Natural, for a total of 2.25 gr/100 dscf for annual emission calculations. The highest 99^{th} percentile daily sulfur concentration during the 7-year record at Sumas was used for the Project's short-term emission estimates: 3.23 gr/100 dscf. Adding 0.25 gr/100 dscf for odorant addition by Cascade Natural resulted in an estimated worst-case short-term natural gas sulfur content of 3.48 gr/100 dscf. Additional details are available on request.

3.2 ESTIMATED EMISSIONS FOR AMBIENT AIR QUALITY STANDARDS AND PSD INCREMENT ANALYSES

Based on the modeling applicability analysis above (and summarized in Table 3-1), ambient air quality modeling is required for PM_{10} and $PM_{2.5}$ for each turbine option, and for CO for the Siemens turbine option only. Long-term (annual) emission rates used in the modeling were calculated using the same methodology that was used to determine the annual bases shown in Table 3-1. These include all new sources (turbine(s) plus emergency generator), and use the worst-case turbine emissions for each load (maximum of full load and/or lower loads, using maximum operating hours for each) at the annually averaged operating condition (51°F). These scenario descriptions are provided above in Section 3.1. Table 3-2 shows the annualized modeled emission rate for particulate matter (PM; PM_{10} and $PM_{2.5}$), along with stack parameters, for each turbine option. Note that there is no annual standard for CO, so it is not included here. More specific details are provided in Attachment A-1 through A-13.

Turbine emissions vary with atmospheric and operating conditions, and may include specific events, such as equipment start-ups and shutdowns. Attachments A-4 and A-5 include detailed emissions estimates for each turbine option at each load basis (100% and 75% for all turbine options (high and medium load, respectively), and 50% for the GE options, 60% and 70% load for the Siemens turbine on natural gas and distillate, respectively (low load), and, additionally, a 30% load option for the LMS100), each ambient temperature (7°F, 51°F, and 88°F), and each fuel type (natural gas and ULSD); these are summarized in Attachment A-3. Vendor data and additional methodology information is provided in Attachments A-6 through A-8. Attachment A-10 provides the start-up and shutdown emission details for all turbine options.

Table 3-1
Estimated Annual Emissions for the Potential Turbine Options

Pollutant	Expected Increased Emissions (tpy)				Significant Emission Rate (tpy)
	GE 7FA.05	GE 7FA.04	Siemens SGT6-5000F4	GE LMS100 (2 Units)	
NO_x	32	31	38	37	40
CO	58	39	*160*	31	100
SO_2	7	6	6	8	40
TSP	*43*	*43*	*32*	*45*	25
PM_{10}	*43*	*43*	*32*	*45*	15
$PM_{2.5}$	*43*	*43*	*32*	*45*	10
VOC	6	5	20	8	40
H_2SO_4	*16*	*14*	*17*	*17*	7
Pb	0.0200	0.0194	0.0194	0.0193	0.6
CO_2e	*311,631*	*274,752*	*302,023*	*327,826*	75,000

Notes:
Emissions estimates are based on equipment vendor data (as provided by Black & Veatch) and operating scenarios provided by PSE.
Emissions estimates are inclusive of turbine(s), one emergency generator, and circuit breakers.
SO_2 and particulate emissions are based on historic annual average sulfur content in natural gas of 2.25 grains (gr) per 100 standard cubic foot (scf) [gr/100 scf] reported at the Williams Northwest Pipeline Sumas compressor station.
Significant Emission Rate (SER) per 40 CFR 52.21(b)(23)(i) and WAC 173-400-030.
Values shown in *italic* indicate exceedance of the SER.
CO_2e emissions in this table are based on CO_2 emission estimates in Attachment A. For reasons cited in Section 5.3.4, CO_2 is the predominant contributor to total CO_2e emissions; emissions of other GHGs (including N_20, CH_4, and SF_6) are in the noise level of (less than 0.01%) of CO_2 estimates.

Table 3-2
Estimated Annual Average Stack Information for Modeling Analyses

Source	Stack Height (ft)	Stack Diameter (ft)	Stack Temperature (°F)	Stack Exit Velocity (fps)	Emissions of PM (lb/hr)
Turbine Option:					
GE 7FA.05	145	23	800	120	9.76
GE 7FA.04	145	21	800	127	9.85
Siemens SGT6-5000F4	145	23	800	118	7.39
GE LMS100 (2 Units)	110	12	777	127	5.12
Emergency Generator	50	0.833	994	146	0.00607

Notes:
Emissions estimates are based on equipment vendor data (as provided by Black & Veatch) and operating scenarios provided by PSE (see Attachment A for details).
Emissions estimates for turbines are based on expected worst-case maximum operation hours over one year, and maximum emissions, by load, for annual average atmospheric conditions.
Emergency generator assumed to operate for a maximum of 275 hrs/yr (52 hrs/yr for testing and maintenance plus the remainder for emergency operations).

Short-term emission rates were developed using worst-case operating scenarios for the specific pollutant over the time period. These worst-case scenarios are dependent upon both the emission rate *and* the stack parameters under each scenario. For example, operation at higher loads may have increased emissions, but a lower load with lower emissions may have stack exhaust features (such as lower flow rate and temperature) that produce higher impacts. A preliminary load-check analysis was conducted to determine worst-case scenarios. This analysis included modeling for 1-hour impacts at each load basis, each ambient temperature, and each fuel type to determine worst-case load scenarios. Table 3-3 shows the results of the load check analysis. (The detailed calculations are provided in Attachment A-10, and the load check modeling (see Section 6.3 below) analyses used in these calculations are provided in Attachment D-3.) The emissions relevant to the criteria pollutant analyses are shown in normal text, with the worst-case operating scenario emission shown in ***bold italic*** font. Emissions of other pollutants not included in the criteria pollutant analyses are shown in shaded text; these values are provided here for informational purposes, and as a reference for some of the Class I area AQRV emission estimates discussed below in Section 3.3.

The worst-case averaging period scenario for full modeling (Section 6 below) was then developed using a combination of worst-case load (that is operationally feasible for the time duration) and start ups and shutdowns when they are operationally feasible for the time duration *and* have the potential to cause higher impacts due to increased emissions. As provided in Attachment A-2, the start-ups and shutdowns are limited to one each per hour (per unit), two in a 3-hr period, five in an 8-hr period, and five in a 24-hr period. Furthermore, start-ups and shutdowns on distillate are limited to one per 24-hr period, with an additional four each on natural gas.

In addition to the start-up and shutdown limits, the GE LMS100’s also have an operational restriction while running on distillate, including no operation below 75% load. Over a 24-hr period, the use factor on distillate is 80 percent, for a total operational time of 38 hours for both units combined. During this time, the turbines can only operate below 100% for 10 percent of this period, or 3.8 hours total. The maximum impact for the GE LMS100’s identified in Table 3-3 shows a combination of 100% and 75% load (distillate, 88°F). Table 3-4 shows the expected worst-case turbine parameters and emissions that are included in the refined modeling analyses, along with the corresponding operating conditions which dictate these stack parameters and emissions. Details of the modeling emission calculations are provided in Attachment A-11.

The emergency generator is also included in the refined modeling analyses. Emissions from the emergency generator include 24 hours of engine testing/maintenance emissions and/or emergency use emissions for modeled averaging periods up to 24-hours, and 500 hours per year, inclusive of 52 hrs of testing/maintenance emissions plus the remaining hours for potential emergency use emissions for annual average modeling. Table 3-5 shows the stack parameters and emissions for the emergency generator. Additional details and references are provided in Attachment A-12.

Table 3-3
Load Check Analysis for the Potential Turbine Options

Averaging Time	Operation ID	Unit ID	Turbine Stack Parameters				Emissions (lb/hr/unit)					Maximum Impact (μg/m³/unit) over all years (1995-1999)				
			Ht (ft)	Temp (°F)	Vel (fps)	Diam (ft)	NO_x	CO	PM	SO_2	Notes:	UNIT*10	NO_x	CO	PM	SO_2
GE 7FA5 - 7°F																
1-hr	NG-100	7F5-G100	145	800	132	23	20.70	19.80	47.70	8.22	NG; 3.48 gr/100 scf; 7°F; 100% load.	42.36	0.88	0.84	2.02	0.35
1-hr	NG-75	7F5-G75	145	800	107	23	16.30	15.80	41.60	6.55	NG; 3.48 gr/100 scf; 7°F; 75% load.	51.94	0.85	0.82	2.16	0.34
1-hr	NG-50	7F5-G50	145	800	93	23	12.70	12.40	36.50	5.13	NG; 3.48 gr/100 scf; 7°F; 50% load.	61.53	0.78	0.76	2.25	0.32
1-hr	D-100	7F5-D100	145	800	124	23	44.10	42.30	38.50	1.26	Distillate; 7°F; 100% load.	45.65	2.01	1.93	1.76	0.06
1-hr	D-75	7F5-D75	145	800	105	23	35.20	34.20	37.70	1.00	Distillate; 7°F; 75% load.	52.56	1.85	1.80	1.98	0.05
1-hr	D-50	7F5-D50	***145***	***799***	***87***	***23***	26.70	27.20	***36.80***	0.79	***Distillate; 7°F; 50% load.***	69.54	1.86	1.89	***2.56***	0.05
GE 7FA5 - 51°F																
1-hr	NG-100	7F5-G100	145	800	131	23	19.40	18.60	45.80	7.72	NG; 3.48 gr/100 scf; 51°F; 100% load.	42.53	0.83	0.79	1.95	0.33
1-hr	NG-75	7F5-G75	145	800	109	23	15.50	15.00	40.50	6.24	NG; 3.48 gr/100 scf; 51°F; 75% load.	51.33	0.80	0.77	2.08	0.32
1-hr	NG-50	7F5-G50	145	799	96	23	12.30	12.00	35.90	4.97	NG; 3.48 gr/100 scf; 51°F; 50% load.	57.82	0.71	0.69	2.08	0.29
1-hr	D-100	7F5-D100	145	800	131	23	44.10	42.30	38.50	1.26	Distillate; 51°F; 100% load.	42.53	1.88	1.80	1.64	0.05
1-hr	D-75	7F5-D75	145	800	110	23	35.00	34.00	37.70	0.99	Distillate; 51°F; 75% load.	51.03	1.79	1.73	1.92	0.05
1-hr	D-50	7F5-D50	145	799	92	23	26.90	26.30	36.80	0.79	Distillate; 51°F; 50% load.	62.85	1.69	1.65	2.31	0.05
GE 7FA5 - 88°F																
1-hr	NG-100	7F5-G100	145	800	129	23	17.90	17.20	43.80	7.14	NG; 3.48 gr/100 scf; 88°F; 100% load.	43.41	0.78	0.75	1.90	0.31
1-hr	NG-75	7F5-G75	145	799	110	23	14.60	14.20	39.20	5.88	NG; 3.48 gr/100 scf; 88°F; 75% load.	51.05	0.75	0.72	2.00	0.30
1-hr	NG-50	7F5-G50	145	800	98	23	11.90	11.60	35.40	4.81	NG; 3.48 gr/100 scf; 88°F; 50% load.	55.38	0.66	0.64	1.96	0.27
1-hr	D-100	7F5-D100	145	800	132	23	42.40	40.70	38.40	1.21	Distillate; 88°F; 100% load.	42.36	1.80	1.72	1.63	0.05
1-hr	D-75	7F5-D75	145	800	112	23	33.90	32.90	37.50	0.96	Distillate; 88°F; 75% load.	50.43	1.71	1.66	1.89	0.05
1-hr	D-50	7F5-D50	145	799	94	23	26.00	25.50	36.70	0.77	Distillate; 88°F; 50% load.	60.31	1.57	1.54	2.21	0.05
GE 7FA4 - 7°F																
1-hr	NG-100	7F4-G100	145	800	135	21	17.40	16.20	46.40	7.01	NG; 3.48 gr/100 scf; 7°F; 100% load.	50.27	0.87	0.81	2.33	0.35
1-hr	NG-75	7F4-G75	145	799	114	21	14.10	13.20	41.20	5.73	NG; 3.48 gr/100 scf; 7°F; 75% load.	55.85	0.79	0.74	2.30	0.32
1-hr	NG-50	7F4-G50	***145***	***799***	***102***	***21***	11.90	11.40	***37.60***	4.82	***NG; 3.48 gr/100 scf; 7°F; 50% load.***	63.46	0.76	0.72	***2.39***	0.31
1-hr	D-100	7F4-D100	145	800	135	21	39.20	34.80	38.40	1.12	Distillate; 7°F; 100% load.	50.27	1.97	1.75	1.93	0.06
1-hr	D-75	7F4-D75	145	799	114	21	31.40	28.80	37.60	0.90	Distillate; 7°F; 75% load.	55.85	1.75	1.61	2.10	0.05
1-hr	D-50	7F4-D50	145	799	102	21	26.40	24.70	36.90	0.78	Distillate; 7°F; 50% load.	63.46	1.68	1.57	2.34	0.05
GE 7FA4 - 51°F																
1-hr	NG-100	7F4-G100	145	800	138	21	16.80	15.60	45.40	6.75	NG; 3.48 gr/100 scf; 51°F; 100% load.	49.55	0.83	0.77	2.25	0.33
1-hr	NG-75	7F4-G75	145	800	116	21	13.60	12.70	40.20	5.47	NG; 3.48 gr/100 scf; 51°F; 75% load.	55.26	0.75	0.70	2.22	0.30
1-hr	NG-50	7F4-G50	145	799	103	21	11.30	10.80	36.50	4.56	NG; 3.48 gr/100 scf; 51°F; 50% load.	62.33	0.70	0.67	2.28	0.28
1-hr	D-100	7F4-D100	145	800	141	21	39.00	35.20	38.40	1.12	Distillate; 51°F; 100% load.	48.59	1.90	1.71	1.87	0.05
1-hr	D-75	7F4-D75	145	799	117	21	30.90	28.70	37.50	0.88	Distillate; 51°F; 75% load.	55.00	1.70	1.58	2.06	0.05
1-hr	D-50	7F4-D50	145	799	104	21	25.50	23.80	36.90	0.75	Distillate; 51°F; 50% load.	61.22	1.56	1.46	2.26	0.05
GE 7FA4 - 88°F																
1-hr	NG-100	7F4-G100	145	800	133	21	15.10	14.30	42.70	6.07	NG; 3.48 gr/100 scf; 88°F; 100% load.	50.77	0.77	0.73	2.17	0.31
1-hr	NG-75	7F4-G75	145	799	115	21	12.40	11.80	38.40	5.02	NG; 3.48 gr/100 scf; 88°F; 75% load.	55.56	0.69	0.66	2.13	0.28
1-hr	NG-50	7F4-G50	145	800	105	21	11.00	10.70	36.00	4.42	NG; 3.48 gr/100 scf; 88°F; 50% load.	60.07	0.66	0.64	2.16	0.27
1-hr	D-100	7F4-D100	145	800	138	21	36.20	32.20	38.10	1.03	Distillate; 88°F; 100% load.	49.55	1.79	1.60	1.89	0.05
1-hr	D-75	7F4-D75	145	799	117	21	29.00	26.70	37.20	0.86	Distillate; 88°F; 75% load.	55.00	1.59	1.47	2.05	0.05
1-hr	D-50	7F4-D50	145	799	108	21	25.40	23.70	36.80	0.74	Distillate; 88°F; 50% load.	57.61	1.46	1.37	2.12	0.04

Table 3-3
Load Check Analysis for the Potential Turbine Options (continued)

Averaging Time	Operation ID	Unit ID	Turbine Stack Parameters				Emissions (lb/hr/unit)					Maximum Impact (μg/m^3) over all years (1995-1999)				
			Ht (ft)	Temp (°F)	Vel (fps)	Diam (ft)	NO_x	CO	PM	SO_2	Notes:	UNIT*10	NO_x	CO	PM	SO_2
Siemens SGT6-5000F4 - 7°F																
1-hr	NG-100	SM-G100	145	800	130	23	21.10	8.40	40.00	7.39	NG; 3.48 gr/100 scf; 7°F; 100% load.	42.97	0.91	0.36	1.72	0.32
1-hr	NG-75	SM-G75	145	799	108	23	17.10	6.80	33.20	6.02	NG; 3.48 gr/100 scf; 7°F; 75% load.	51.65	0.88	0.35	1.71	0.31
1-hr	NG-50	SM-G60	145	800	96	23	14.60	14.40	29.50	5.13	NG; 3.48 gr/100 scf; 7°F; 60% load.	57.78	0.84	0.83	1.70	0.30
1-hr	D-100	SM-D100	145	800	126	23	43.10	20.80	34.60	1.09	Distillate; 7°F; 100% load.	44.75	1.93	0.93	1.55	0.05
1-hr	D-75	SM-D75	***145***	***799***	***103***	***23***	33.80	***49.60***	33.60	0.85	***Distillate; 7°F; 75% load.***	53.21	1.80	***2.64***	1.79	0.05
1-hr	D-50	SM-D70	145	799	99	23	32.10	46.80	33.40	0.81	Distillate; 7°F; 70% load.	54.51	1.75	2.55	1.82	0.04
Siemens SGT6-5000F4 - 51°F																
1-hr	NG-100	SM-G100	145	800	129	23	19.70	7.60	37.00	6.91	NG; 3.48 gr/100 scf; 51°F; 100% load.	43.41	0.86	0.33	1.61	0.30
1-hr	NG-75	SM-G75	145	800	106	23	15.70	6.00	31.10	5.51	NG; 3.48 gr/100 scf; 51°F; 75% load.	52.25	0.82	0.31	1.62	0.29
1-hr	NG-50	SM-G60	145	799	94	23	13.40	13.20	27.70	4.71	NG; 3.48 gr/100 scf; 51°F; 60% load.	60.31	0.81	0.80	1.67	0.28
1-hr	D-100	SM-D100	145	800	121	23	38.80	18.80	34.10	0.98	Distillate; 51°F; 100% load.	47.01	1.82	0.88	1.60	0.05
1-hr	D-75	SM-D75	145	800	101	23	31.00	45.20	33.30	0.78	Distillate; 51°F; 75% load.	53.83	1.67	2.43	1.79	0.04
1-hr	D-50	SM-D70	145	800	97	23	29.40	42.80	33.10	0.74	Distillate; 51°F; 70% load.	56.57	1.66	2.42	1.87	0.04
Siemens SGT6-5000F4 - 88°F																
1-hr	NG-100	SM-G100	145	800	124	23	17.70	6.80	34.10	6.22	NG; 3.48 gr/100 scf; 88°F; 100% load.	45.65	0.81	0.31	1.56	0.28
1-hr	NG-75	SM-G75	145	799	104	23	14.30	5.60	29.00	5.02	NG; 3.48 gr/100 scf; 88°F; 75% load.	52.89	0.76	0.30	1.53	0.27
1-hr	NG-50	SM-G60	145	799	92	23	12.20	12.00	26.00	4.30	NG; 3.48 gr/100 scf; 88°F; 60% load.	62.85	0.77	0.75	1.63	0.27
1-hr	D-100	SM-D100	145	800	116	23	34.80	16.80	33.70	0.88	Distillate; 88°F; 100% load.	49.27	1.71	0.83	1.66	0.04
1-hr	D-75	SM-D75	145	799	98	23	28.10	41.20	33.00	0.71	Distillate; 88°F; 75% load.	55.42	1.56	2.28	1.83	0.04
1-hr	D-50	SM-D70	***145***	***799***	***95***	***23***	26.70	38.80	***32.80***	0.67	***Distillate; 88°F; 70% load.***	59.06	1.58	2.29	***1.94***	0.04
GE LMS100 - 7°F																
1-hr	NG-100	LM-G100	110	737	134	12	7.90	7.20	17.50	3.18	NG; 3.48 gr/100 scf; 7°F; 100% load.	291.38	2.30	2.10	5.10	0.93
1-hr	NG-75	LM-G75	110	764	115	12	6.40	4.80	15.30	2.57	NG; 3.48 gr/100 scf; 7°F; 75% load.	314.56	2.01	1.51	4.81	0.81
1-hr	NG-50	LM-G50	110	800	96	12	4.90	3.70	13.00	1.96	NG; 3.48 gr/100 scf; 7°F; 50% load.	354.59	1.74	1.31	4.61	0.69
1-hr	NG-30	LM-G30	110	799	79	12	3.50	3.40	11.10	1.42	NG; 3.48 gr/100 scf; 7°F; 30% load.	432.89	1.52	1.47	4.81	0.61
1-hr	D-100	LM-D100	110	754	134	12	16.50	4.80	26.70	0.49	Distillate; 7°F; 100% load.	289.46	4.78	1.39	7.73	0.14
1-hr	D-75	LM-D75	110	782	115	12	13.30	4.60	26.40	0.39	Distillate; 7°F; 75% load.	312.89	4.16	1.44	8.26	0.12
1-hr	D-50	LM-D50	110	800	97	12	10.10	4.30	26.00	0.30	Distillate; 7°F; 50% load.	351.77	3.55	1.51	9.15	0.11
GE LMS100 - 51°F																
1-hr	NG-100	LM-G100	110	769	136	12	8.10	6.20	17.80	3.26	NG; 3.48 gr/100 scf; 51°F; 100% load.	285.35	2.31	1.77	5.08	0.93
1-hr	NG-75	LM-G75	110	787	117	12	6.50	4.50	15.40	2.62	NG; 3.48 gr/100 scf; 51°F; 75% load.	309.59	2.01	1.39	4.77	0.81
1-hr	NG-50	LM-G50	110	800	98	12	5.00	3.80	13.20	1.99	NG; 3.48 gr/100 scf; 51°F; 50% load.	348.97	1.74	1.33	4.61	0.69
1-hr	NG-30	LM-G30	110	799	80	12	3.60	3.90	11.20	1.44	NG; 3.48 gr/100 scf; 51°F; 30% load.	426.86	1.54	1.66	4.78	0.61
1-hr	D-100	LM-D100	110	786	136	12	16.90	5.00	26.70	0.50	Distillate; 51°F; 100% load.	283.62	4.79	1.42	7.57	0.14
1-hr	D-75	LM-D75	110	799	117	12	13.50	4.70	26.40	0.40	Distillate; 51°F; 75% load.	308.50	4.16	1.45	8.14	0.12
1-hr	D-50	LM-D50	110	800	99	12	10.30	4.50	26.10	0.30	Distillate; 51°F; 50% load.	346.17	3.57	1.56	9.04	0.10
GE LMS100 - 88°F																
1-hr	NG-100	LM-G100	110	799	132	12	7.90	5.70	17.40	3.16	NG; 3.48 gr/100 scf; 88°F; 100% load.	287.71	2.27	1.64	5.01	0.91
1-hr	NG-75	LM-G75	110	800	114	12	6.30	4.30	15.10	2.53	NG; 3.48 gr/100 scf; 88°F; 75% load.	312.70	1.97	1.34	4.72	0.79
1-hr	NG-50	LM-G50	110	800	97	12	4.80	4.00	12.90	1.92	NG; 3.48 gr/100 scf; 88°F; 50% load.	351.77	1.69	1.41	4.54	0.68
1-hr	NG-30	LM-G30	110	799	80	12	3.50	4.40	11.00	1.40	NG; 3.48 gr/100 scf; 88°F; 30% load.	426.86	1.49	1.88	4.70	0.60
1-hr	**D-100**	**LM-D100**	**110**	**800**	**129**	**12**	15.70	5.00	**26.60**	0.46	**Distillate; 88°F; 100% load.**	291.69	4.58	1.46	***7.76***	0.13
1-hr	**D-75**	**LM-D75**	**110**	**800**	**113**	**12**	12.70	4.50	**26.30**	0.37	**Distillate; 88°F; 75% load.**	314.14	3.99	1.51	***8.26***	0.12
1-hr	D-50	LM-D50	110	799	96	12	9.60	5.70	26.00	0.28	Distillate; 88°F; 50% load.	354.67	3.40	1.60	9.22	0.10

NOTE: Maximum Impact for determination of worst-case scenario is dependent on feasible operations. PSE has opted to limit distillate use for the GE LMS100 option to a 80% use factor over a 24-hr period (for both units, for a combined usage of 38 hours) with minimum load at 75% during this time. Furthermore, during this period, the load is restricted to remain at 100% for all but 10% of the time (3.8 hours combined between 75 and 99% load).

3.3 ESTIMATED EMISSIONS USED IN AIR QUALITY RELATED VALUES ANALYSIS

The AQRV analysis is required for Class I and some Class II wilderness areas. A conservative methodology was used to develop emission rates for these analyses in order to simplify the modeling and reduce computation time. Instead of defining worst-case emissions for each turbine option, as was done for the ambient air quality analysis emissions discussed in Section 3.2, only one worst-case operating scenario and emission set was developed. A discussion of the operating scenario is presented in the AQRV section of this application (Section 7). The worst-case emission rates, for each fuel type, were determined by finding the maximum emission for each pollutant and averaging period, for any turbine option. Details showing the process for choosing these maximum emission rates are provided in Attachment A-11. Section 7.3.4 of this application includes more details regarding the full emission set (including derivative pollutant emissions) used in the AQRV analyses.

3.4 ESTIMATED HAZARDOUS / TOXIC AIR POLLUTANT EMISSIONS

The proposed Project also has the potential to emit non-criteria air pollutants, known as hazardous and/or toxic air pollutants. Hazardous air pollutant (HAP) emissions are evaluated for major source thresholds, and toxic air pollutant (TAP) emissions are compared to Washington State's Small Quantity Emission Rates (SQERs) and Acceptable Source Impact Levels (ASILs), as necessary. Table 3-6 shows these values for each turbine option (including the emergency generator), by TAP (for respective averaging period), and as total annual HAPs. With the exception of Washington State TAPs that are also criteria pollutants, emission rates are based on maximum fuel use by averaging period, using primarily California Air Toxics Emission Factors (CATEF) in pounds per fuel input (www.arb.ca.gov/ei/catef/catef.htm); emission rates for TAPs that are also criteria pollutants are calculated using the vendor data provided in Attachment A. EPA's AP-42 emission factors were used as a secondary source for turbine TAP emission factors after CATEF and for the diesel-fired emergency generator factors. Details for the emission factors are provided in Attachment E-1. As with the criteria pollutant emissions, annual fuel use is based on annual average operating conditions, assuming maximum fuel use for load options. Short-term emissions use maximum fuel usage for both fuel types over the three atmospheric conditions and three operating loads; these do not include start-up or shutdown fuel usage, which is expected to be lower than operational fuel use. Emissions of NO_2, CO, PM, SO_2, and H_2SO_4 were taken directly from the emission estimates used in the criteria pollutant analysis, and include start-up/shutdown emissions in the worst-case short-term period (1-hr for the NO_2 SQER). Ammonia (NH_3) emissions were based on vendor data for the NH_3 slip from the NO_x control (see Section 5 for more details on control technology).

The maximum total HAPs for any turbine option is 4.49 tpy, well below the major HAP threshold of 25 tpy (or individual major HAP threshold of 10 tpy). However, TAPs that exceed their specific SQER require additional analysis (as explained in Section 4). These TAP emissions are shown in bold in the table, and include the following: 1,3-Butadiene, Acetaldehyde, Acrolein, Ammonia, Arsenic, Benz(a)anthracene, Benzene, Benzo(a)pyrene, Benzo(b)fluoranthene, Benzo(k)fluoranthene, Beryllium, Cadmium, Carbon Monoxide, Chromium(VI), Dibenz(a,h)anthracene, Diesel Engine Exhaust Particulate, Ethylbenzene, Formaldehyde, Hydrogen Chloride, Indeno(1,2,3-cd)pyrene, Manganese, Naphthalene, Nitrogen Dioxide, Propylene Oxide, Sulfur Dioxide, Sulfuric Acid, and Vinyl Chloride. Emission factor details and calculation methodologies are provided in Attachment E.

Table 3-4
Refined Modeling – Worst Case Scenario Emissions for the Potential Turbine Options

Averaging Period	Turbine Stack Parameters				Emission Rate (lb/hr/unit)		Scenario Description
	Ht (ft)	Temp (°F)	Vel (fps)	Diam (ft)	PM	CO	
GE 7FA5							
Ann	145	800	120	23	9.76	--	Annual NG and Distillate - all loads based on predicted use (op scenarios); NG at 2.25 gr/100 scf; ave temp (51°F).
24-hr	145	799	87	23	36.80	--	Distillate; 50% load; 7°F; no SU/SD.
GE 7FA4							
Ann	145	800	127	21	9.85	--	Annual NG and Distillate - all loads based on predicted use (op scenarios); NG at 2.25 gr/100 scf; ave temp (51°F).
24-hr	145	799	102	21	37.60	--	NG at 3.48 gr/100 scf; 50% load; 7°F; no SU/SD.
Siemens SGT6-5000F4							
Ann	145	800	118	23	7.39	--	Annual NG and Distillate - all loads based on predicted use (op scenarios); NG at 2.25 gr/100 scf; ave temp (51°F).
24-hr	145	799	95	23	32.80	--	Distillate; 70% load; 88°F; no SU/SD.
1-hr	145	799	103	23	--	2173	Distillate; 75% load; 7°F; 1 Distillate SU/SD.
8-hr	145	799	103	23	--	1203	Distillate; 75% load; 7°F; 1 Distillate SU/SD over 1 hr, and additional 4 NG SU/SD over 8 hr period.
GE LMS100							
Ann	110	777	127	12	5.12	--	Annual NG and Distillate - all loads based on predicted use (op scenarios); NG at 2.25 gr/100 scf; ave temp (51°F).
24-hr	110	800	129	12	18.52	--	Distillate 80% (combined for 2 units) use factor over 24 hr period; 90% use at 100% load; 88°F.
	110	800	113	12	2.83	--	Distillate 80% (combined for 2 units) use factor over 24 hr period; 10% use down to 75% load; 88°F; 1 Distillate SU/SD.

Table 3-5
Refined Modeling – Worst Case Scenario Emissions for the Emergency Generator

Averaging Period	Generator Stack Parameters				Emission Rate (lb/hr)		Scenario Description
	Ht (ft)	Temp (°F)	Vel (fps)	Diam (ft)	PM	CO	
Caterpillar C18							
Ann	50	994	146	0.833	0.00607	--	Distillate; full load; 500 hrs/yr, inclusive of 52 hrs testing and maintenance plus potential emergency operation.
24-hr	50	994	146	0.833	0.1063	--	Distillate; full load; 24 hrs (full time).
1-hr	50	994	146	0.833	--	1.063	Distillate; full load; 1 hr (full time).
8-hr	50	994	146	0.833	--	1.063	Distillate; full load; 8 hrs (full time).

Note: Total operation hours for the emergency generator will be limited to 275 hrs/yr. The emissions provided in this application are based on this annual value. However, for the modeling impact analyses, emissions were based on the conservative 500 hrs/yr, *except* for the Diesel Engine Exhaust Particulate (TAP) impact analysis which used the revised 275 hrs/yr operation.

Table 3-6 Estimated Toxic and Hazardous Air Pollutant Emissions for the Potential Turbine Options												
			Washington State SQERs		Maximum Emissions (lb/averaging period)				Maximum Annual HAP Emissions (lb/yr)			
Common Name	TAP	HAP	Averaging Period	SQER (lb/averaging period)	GE 7FA.05	GE 7FA.04	Siemens SGT6-5000F4	GE LMS100 (2 Units)	GE 7FA.05	GE 7FA.04	Siemens SGT6-5000F4	GE LMS100 (2 Units)
Washington Toxic Air Pollutants (TAPs) per 173-460-150												
1,1-Dichloroethylene	Yes	Yes	24-hr	26.3	1.09	0.98	1.04	0.84	15.3	13.7	14.6	11.8
1,3-Butadiene	Yes	Yes	year	1.13	**12.5**	**11.2**	**12.0**	**9.8**	12.5	11.2	12.0	9.8
Acetaldehyde	Yes	Yes	year	71	**2207**	**1879**	**2187**	**2292**	2207	1879	2187	2292
Acrolein	Yes	Yes	24-hr	0.00789	**3.72**	**3.17**	**3.69**	**2.99**	299	255	297	311
Ammonia	Yes		24-hr	9.31	**768**	**689**	**732**	**595**				
Arsenic & Inorganic Arsenic Compounds	Yes	Yes	year	0.0581	**1.48**	**1.33**	**1.41**	**1.14**	1.48	1.33	1.41	1.14
Benz[a]anthracene	Yes		year	1.74	**2.25**	**1.99**	**2.16**	**1.89**				
Benzene	Yes	Yes	year	6.62	**269**	**232**	**265**	**264**	269	232	265	264
Benzo[a]pyrene	Yes		year	0.174	**2.06**	**1.83**	**1.98**	**1.70**				
Benzo[b]fluoranthene	Yes		year	1.74	**1.96**	**1.74**	**1.88**	1.59				
Benzo[k]fluoranthene	Yes		year	1.74	**1.96**	**1.74**	**1.88**	1.59				
Beryllium & Compounds	Yes	Yes	year	0.08	**0.75**	**0.67**	**0.71**	**0.58**	0.75	0.67	0.71	0.58
Cadmium & Compounds	Yes	Yes	year	0.0457	**1.94**	**1.74**	**1.85**	**1.50**	1.94	1.74	1.85	1.50
Carbon monoxide	Yes		1-hr	50.4	**538**	**537**	**2175**	**108**				
Chromium(VI)	Yes	Yes	year	0.00128	**0.09**	**0.08**	**0.09**	**0.07**	0.089	0.080	0.085	0.069
Chrysene	Yes		year	17.4	2.32	2.05	2.23	1.97				
Copper & Compounds	Yes		1-hr	0.219	0.02	0.02	0.02	0.02				
Dibenz[a,h]anthracene	Yes		year	0.16	**2.24**	**1.99**	**2.16**	**1.89**				
Diesel Engine Exhaust, Particulate	Yes		year	0.639	***13338***	***13304***	***11845***	***18503***				
Ethylbenzene	Yes	Yes	year	76.8	**246**	**210**	**244**	**256**	246	210	244	256
Formaldehyde	Yes	Yes	year	32	**1799**	**1542**	**1775**	**1812**	1799	1542	1775	1812
Hydrogen Chloride	Yes	Yes	24-hr	1.18	**33.5**	**30.0**	**31.9**	**25.9**	469	420	447	362
Indeno[1,2,3-cd]pyrene	Yes		year	1.74	**2.24**	**1.99**	**2.16**	**1.89**				
Lead and compounds (NOS)	Yes	Yes	year	16	3.91	3.51	3.73	3.02	3.91	3.51	3.73	3.02
Manganese & Compounds	Yes	Yes	24-hr	0.00526	**5.56**	**4.99**	**5.30**	**4.30**	77.8	69.8	74.2	60.2
Mercury, Elemental	Yes	Yes	24-hr	0.0118	0.0020	0.0018	0.0019	0.0015	0.028	0.025	0.027	0.022
m-Xylene	Yes	Yes	24-hr	29.0	6.41	5.55	6.36	5.87	467	397	463	485
Naphthalene	Yes	Yes	year	5.64	**185**	**164**	**178**	**152**	185	164	178	152
n-Hexane	Yes		24-hr	92.0	20.4	17.3	20.2	16.2				
Nitrogen dioxide	Yes		1-hr	1.03	**242**	**241**	**246**	**151**				
o-Xylene	Yes	Yes	24-hr	29.0	3.25	2.87	3.23	3.37	211	180	209	220
Perchloroethylene	Yes	Yes	year	32.4	24.5	22.0	23.4	19.0	24.5	22.0	23.4	19.0
Propylene	Yes		24-hr	394	116	100	115	103				
Propylene oxide	Yes	Yes	year	51.8	**254**	**216**	**251**	**263**	254	216	251	263
p-Xylene	Yes	Yes	24-hr	29.0	6.41	5.55	6.36	5.87	467	397	463	485
Selenium & Selenium Cmpnds	Yes	Yes	24-hr	2.63	0.0035	0.0032	0.0034	0.0027	0.05	0.04	0.05	0.04
Sulfur dioxide	Yes		1-hr	1.45	**16.5**	**16.2**	**17.4**	**16.7**				
Sulfuric Acid	Yes		24-hr	0.131	**528**	**606**	**552**	**419**				
Toluene	Yes	Yes	24-hr	657	9.90	8.57	9.82	9.00	726	618	720	754
Trichloroethylene	Yes	Yes	year	95.9	20.8	18.7	19.8	16.1	20.8	18.7	19.8	16.1
Vinyl Chloride	Yes	Yes	year	2.46	**39.9**	**35.8**	**38.0**	**30.8**	39.9	35.8	38.0	30.8
Additional Federal Hazardous Air Pollutants (HAPs) (per CAA 112b) not identified above (or shown compounded (but not included again in total HAP calculation)).												
Chromium Compounds		Yes							3.05	2.73	2.91	2.36
Nickel Compounds		Yes							2050	1839	1955	1585
Xylenes (isomers and mixtures)		Yes							271	230	268	281
Total HAP Compounds (lb/yr)									8977	7787	8780	8490
Total HAP Compounds (tpy)									**4.49**	**3.89**	**4.39**	**4.25**

NOTES:

TAPs shown in **bold** exceed the Washington SQER and are modeled to compare with ASIL (see Section 8).

Turbine emissions listed under "Diesel Engine Exhaust, Particulate" are included here as total particulate emissions from diesel-firing of the gas turbines. Ecology has not yet determined whether these turbine emissions are part of "Diesel Engine Exhaust, Particulate", but are included for conservatism at this time.

4.1 REGULATORY APPLICABILITY REVIEW

4.1.1 Prevention of Significant Deterioration (PSD)

As described above, Ecology is the state-level governing body for air quality in Washington. In addition, the state is divided into multiple air pollution control agencies. The Mount Vernon site is located within NWCAA's authority. The air pollution control agencies defer to Ecology for major source attainment permitting issues, such as PSD. This PSD application also serves as the NOC application to NWCAA.

The existing facility is a PSD major source. The New Source Review (NSR) process is triggered for sources that emit emissions in excess of the SERs listed in WAC 173-400-030 (27 – Emission Threshold), and 40 CFR 52.21(b)(23)(i). As shown above in Table 3-1, some of these SERs are expected to be exceeded for the facility, depending on the pollutant and turbine option. As a result, the Project triggers the PSD NSR process. As stated in the Introduction, the Project region is in attainment for all criteria air pollutants. Thus PSD applies, and federal non-attainment NSR rules currently do not.

PSD rules require a BACT analysis to ensure the use of the most effective air pollution control equipment and procedures. As demonstrated by emissions information provided in Table 3-1, a BACT analysis is required for CO, PM (including PM_{10} and $PM_{2.5}$), H_2SO_4, and greenhouse houses (GHGs). Washington regulations require a separate BACT analysis for other pollutants for the NOC application. Section 5 of this application presents this analysis, and demonstrates that the Project will meet BACT requirements for the applicable PSD and non-PSD pollutants. Requirements for ambient air quality impact modeling to demonstrate compliance with ambient air quality standards and PSD increments include the following:

- Description of the project, including emissions, fuel type(s), control technologies, and stack characteristics;
- The basis for all emission estimates and/or calculations;
- Existing baseline data for all regulated pollutants;
- A description of the meteorological data; and
- A worst-case air quality impact assessment, including an assessment of cumulative impacts if necessary.

The criteria pollutant modeling analyses are provided in Section 6 of this application.

The PSD program is also the mechanism for evaluating the effects of an applicable Project's air emissions on environmentally related areas, such as visibility, soils, and vegetation. These evaluations are provided in Section 7 of this application. These PSD-required evaluations also fulfill requirements in WAC 173-400-110, outlining the NOC process. As mentioned above, the PSD application also serves as the NOC application to NWCAA.

4.1.2 New Source Performance Standards (NSPS)

New source performance standards (NSPS) have been established by EPA to limit air pollutant emissions from certain categories of new and modified stationary sources. The NSPS regulations are contained in 40 CFR Part 60 and cover many different industrial source categories. Stationary gas turbines are regulated under Subpart KKKK. The enforcement of NSPS has been delegated to Ecology, and the NSPS regulations are incorporated by reference into WAC 173-

400-115. In general, local emission limitation rules or BACT requirements are far more restrictive than the NSPS requirements. In this case, the controlled NO_x emission rate from any of the project's natural gas-fired turbine options is less than 0.13 pound (lb) of NO_x per MW-hr, will be well below the Subpart KKKK requirement of 0.39 lb of NO_x per MW-hr. Similarly, the projected maximum SO_2 emissions from any of the gas turbine options will be about 0.05 lb of SO_2 per MW-hr, which is substantially less than the Subpart KKKK requirement of 0.58 lb of SO_2 per MW-hr.

NSPS fuel requirements for SO_2 will be satisfied by the use of natural gas as the primary fuel for the gas turbine generator(s), and emissions and fuel monitoring will be performed to demonstrate compliance. The use of ULSD as backup fuel also meets these requirements. There are no NSPS requirements for other air pollutants in Subpart KKKK.

40 CFR 60 Subpart IIII applies to the proposed emergency generator. Engine manufacturers are required to certify engines for prescribed NO_x, PM, CO, and VOC emission standards, and operators are required to follow manufacturer's operation and maintenance instructions. Subpart IIII also limits emergency engines to 100 hours per year of non-emergency operation (i.e., maintenance and testing). The proposed engine for the Project will be a certified unit, and this application has been prepared with the assumption of a maximum of 52 hours per year of non-emergency use.

4.1.3 Acid Rain Program Requirements

Title IV of the Clean Air Act Amendments (CAAA) applies to sources of air pollutants that contribute to acid rain formation, including certain sources of SO_2 and NO_x emissions. Title IV is implemented by the EPA under 40 CFR 72, 73, and 75. Allowances for SO_2 emissions are set aside, as required in 40 CFR 73. Sources subject to Title IV are required to obtain the necessary SO_2 allowances, to monitor their emissions, and obtain the appropriate amount of SO_2 allowances when a new source is permitted. Sources such as the proposed project that use pipeline-quality natural gas are exempt from many of the acid rain program requirements. However, these sources must still estimate SO_2 and carbon dioxide (CO_2) emissions, and monitor NO_x emissions with a certified continuous emissions monitoring system (CEMS). All subject facilities must submit an acid rain permit application to EPA within 24 months of commencing operation.

4.2 AMBIENT AIR QUALITY STANDARDS (AAQS)

The Clean Air Act of 1970 mandated that the EPA establish ambient ceilings for certain pollutants based upon the identifiable effects that pollutants might have on the public health and welfare. Subsequently, EPA promulgated regulations which set National Ambient Air Quality Standards (NAAQS) for SO_2, TSP, NO_2, CO, non-methane hydrocarbons (NMHC), photochemical oxidants as ozone (O_3), and lead (Pb). The standard for NMHC was eventually changed to a guideline and the ozone standard was revised. After further review, the NAAQS for NMHC was revoked in 1983. A new ambient standard to control ambient concentrations of PM_{10} was promulgated by EPA on July 1, 1987 to replace ambient standards for TSP. In 1997, EPA added standards for $PM_{2.5}$. Pollutants having NAAQS are collectively referred to as criteria pollutants.

Pursuant to the Clean Air Act and its amendments, Washington has adopted the Federal standards for some criteria pollutants, promulgated more stringent standards for others, and promulgated standards for additional pollutants. Ecology has retained the TSP air quality standard. The Federal and Washington Ambient Air Quality Standards are shown in Table 4-1.

Section 107 of the 1977 Clean Air Act Amendments required both the EPA and individual states to evaluate the attainment of the NAAQS. Areas not meeting the NAAQS are designated as non-attainment areas. For these non-attainment areas, states are required to revise their State Implementation Plan (SIP) to provide for attainment of the NAAQS as expeditiously as practical, within certain time limits. Areas lacking in sufficient data for determination of attainment or non- attainment status are designated as unclassifiable, but are treated as being attainment areas until designated otherwise. The classification of an area is made on a pollutant specific basis. The PSE facility is located in Skagit County. Air quality throughout Skagit County is currently designated as unclassifiable or in attainment of each State and/or Federal AAQS.

4.3 AMBIENT AIR QUALITY ANALYSES

As part of the PSD permitting process, continued compliance with the State and Federal air quality standards must be demonstrated through the use of dispersion models. The modeling simulation predicts the impact of the proposed facility and, where applicable, existing background sources. To account for regional background levels and unmodeled sources of the relevant pollutants, a measured background concentration is added to the predicted concentration. This total concentration is then compared to the ambient air quality standards to assess compliance.

EPA has defined a set of impact levels that are used to determine whether a multi-source air quality impact analysis needs to be performed to assess compliance with the NAAQS. These significant impact levels (SILs), which have been adopted by Washington, are shown in Table 4-2. The SILs are generally 1 to 5 percent of the NAAQS (typically 4 percent), and are thus well below any levels which could lead to adverse health or welfare impacts. Impacts below these SILs are presumed to be insignificant. The SILs for the recently revised 1-hour NO_2 and 1-hour SO_2 standards have not yet been finalized. The values shown in Table 4-2 are conservative estimates based on current available information from EPA and recent communication with Ecology staff.

In addition to the SILs described above, EPA has proposed SILs for Class I areas, as shown below in Table 4-3. The FLM-recommended SILs are also shown in this table. As with the Class II areas (all areas in the region that are *not* designated as Class I), if the source does not exceed the SILs, evaluation of cumulative impacts is not required. For the proposed Project, the impact assessment was performed using dispersion models (see Sections 6 and 7). The modeling approaches used for both Class I (all greater than 50 km from the source) and Class II areas are discussed in more detail in the Modeling Protocol (Attachment B) and in Sections 6 and 7 of this application.

EPA and Ecology typically require an applicant to evaluate cumulative impacts of all sources at locations where predicted concentrations attributable to the proposed facility are above the SILs. As will be shown in Section 6 of this application, the Project will not exceed any SILs, therefore cumulative analysis is not required for this permit application.

Table 4-1
Federal and State Ambient Air Quality Standards

Pollutant	Averaging Period	National Standards		Washington State Standards	Details
		Primary	Secondary		
Ozone (O_3)	8-hour	0.075 ppm	0.075 ppm		The 3-year average of the 4th highest daily 8-hour maximum is not to be above this level.
	1-hour (Daily Maximum)			0.12 ppm (235 μg/m^3)	Not to be above this level on more than 1 day in a calendar year.
Particulate Matter less than 2.5 microns in diameter ($PM_{2.5}$)	Annual (Arithmetic Mean)	15.0 μg/m^3	15.0 μg/m^3		The 3-year average from a community-oriented monitor is not to be above this level.
	24-hour	35 μg/m^3	35 μg/m^3		The 3-year average of the annual 98th percentile for each population-oriented monitor within an area is not to be above this level.
Particulate Matter less than 10 microns in diameter (PM_{10})	Annual (Arithmetic Mean)			50 μg/m^3	The 3-year average of annual arithmetic mean concentrations at each monitor within an area is not to be above this level.
	24-hour	150 μg/m^3	150 μg/m^3	150 μg/m^3	Not to be above this level on more than three days over 3 years with daily sampling.
Carbon Monoxide (CO)	8-hour	9 ppm (10 mg/m^3)		9 ppm (10 mg/m^3)	Not to be above this level more than once in a calendar year.
	1-hour	35 ppm (40 mg/m^3)		35 ppm (40 mg/m^3)	Not to be above this level more than once in a calendar year.
Nitrogen Dioxide (NO_2)	Annual (Arithmetic Mean)	0.053 ppm (100 μg/m^3)	0.053 ppm (100 μg/m^3)	0.05 ppm (100 μg/m^3)	Not to be above this level in a calendar year.
	1-hour	0.100 ppm			The 3-year average of the 98th percentile of the daily maximum 1-hour average at each monitor is not to be above this level.
Sulfur Dioxide (SO_2)	Annual (Arithmetic Mean)	0.03 ppm		0.02 ppm	Not to be above this level in a calendar year.
	24-hour	0.14 ppm		0.10 ppm	Not to be above this level more than once in a calendar year.
	3-hour		0.5 ppm (1300 μg/m^3)		Not to be above this level more than once in a calendar year.
	1-hour	0.075 ppm		0.40 / 0.25 ppm	State Standards: Not to be above this level more than once in a calendar year / Not to be above this level more than twice in a consecutive 7-day period. Federal Standard: The 3-year average of the 99th percentile of the daily maximum 1-hour average at each monitor is not to be above this level.
	5-minute			0.80 ppm	This is the Northwest Clean Air Agency's standard, which applies in Island, Skagit, and Whatcom counties.
Lead (Pb)	Rolling 3-Month Average	0.15 μg/m^3	0.15 μg/m^3		Not to be above this level.
	Quarterly Average	1.5 μg/m^3	1.5 μg/m^3		
Total Suspended Particulate (TSP)	Annual (Geometric Mean)			60 μg/m^3	Not to be above this level.
	24-hour			150 μg/m^3	Not to be above this level more than once in a calendar year.

Source: EPA 40 CFR Patr 50 (http://www.epa.gov/air/criteria.html) and WAC Chapters 173-470 through 173-475 (http://www.ecy.wa.gov/laws-rules/ecywac.html#air)

Table 4-2
Significant Impact Levels[1]
(micrograms per cubic meter (μg/m³))

Pollutant	Annual	24-Hour	8-Hour	3-Hour	1-Hour
CO	- -	- -	500	- -	2,000
$PM_{2.5}$	0.3 [2]	1.2 [2]	- -	- -	- -
PM_{10}	1.0	5.0	- -	- -	- -
SO_2	1.0	5.0	- -	25.0	30.0 [3] / 7.8 [4]
NO_2	1.0	- -	- -	- -	7.6 [5]

[1] WAC 173-400-720, unless otherwise noted.

[2] PM2.5 SILs finalized by EPA (Volume 75 of the Federal Register (FR) Number 202 [75 FR 202], October 20, 2010).

[3] The SIL of 30 μg/m³ is for the Washington State 1-hr SO_2 limit (WAC 173-400-720).

[4] EPA has provided guidance for conducting impact analyses for compliance demonstration of the new 1-hour SO_2 standard (EPA, *General Guidance for Implementing the 1-hour SO_2 National Ambient Air Quality Standard in Prevention of Significant Deterioration Permits, Including an Interim 1-hour SO_2 Significant Impact Level*, Memorandum from Anna Marie Wood (Office of Air Quality Planning and Standards) to Regional Air Division Directors, August 23, 2010). This guidance suggests a SIL of 3 parts per billion (ppb), the equivalent of 7.8 μg/m³, to be compared to 1) “the highest of the 5-year averages of the maximum modeled 1-hour SO_2 concentrations predicted each year at each receptor, based on 5 years of National Weather Service data”; or 2) “the highest modeled 1-hour SO_2 concentration predicted across all receptors based on 1 year of site-specific meteorological data, or the highest of the multi-year averages of the maximum modeled 1-hour SO_2 concentrations predicted each year at each receptor, based on 2 or more, up to 5 complete years of available site-specific meteorological data.

[5] EPA has provided guidance for conducting impact analyses for compliance demonstration of the new 1-hour NO_2 standard (EPA, *General Guidance for Implementing the 1-hour NO_2 National Ambient Air Quality Standard in Prevention of Significant Deterioration Permits, Including an Interim 1-hour NO_2 Significant Impact Level*, Memorandum from Anna Marie Wood (Office of Air Quality Planning and Standards) to Regional Air Division Directors, June 28, 2010). This guidance suggests a SIL of 4 ppb (the equivalent of 7.6 μg/m³), to be compared to 1) “the highest of the 5-year averages of the maximum modeled 1-hour NO_2 concentrations predicted each year at each receptor, based on 5 years of National Weather Service data”; or 2) “the highest modeled 1-hour NO_2 concentration predicted across all receptors based on 1 year of site-specific meteorological data, or the highest of the multi-year averages of the maximum modeled 1-hour NO_2 concentrations predicted each year at each receptor, based on 2 or more, up to 5 complete years of available site-specific meteorological data.

Table 4-3
Significant Impact Levels at Class I Areas[1]
(micrograms per cubic meter (μg/m^3))

Pollutant	Averaging Period	EPA SIL	FLM SIL
PM_{10}	Annual	0.2	0.08
	24-hour	0.3	0.27
$PM_{2.5}$	Annual	0.06 [2]	- -
	24-hour	0.07 [2]	- -
SO_2	Annual	0.1	0.03
	24-hour	0.2	0.07
	3-hour	1.0	0.48
NO_2	Annual	0.1	0.03

1 EPA proposed and FLM recommended SILs (61 FR 142, July 23, 1996), unless otherwise noted. These have not been finalized to date.

2 PM2.5 SILs finalized by EPA (75 FR 202, October 20, 2010).

4.4 AIR QUALITY RELATED VALUES (AQRV) AND VISIBILITY

Because the Project is subject to PSD, an analysis of AQRV at Class I areas within 100 km of the facility may also be required for this facility. WAC 173-400-030-16 lists the Class I areas in Washington. North Cascades National Park (NCNP), Olympic National Park (ONP), and Glacier Peak Wilderness (GPW) are the only Class I areas within this range. AQRVs include: regional visibility or haze; the effects of primary and secondary pollutants on sensitive plants; the effects of pollutant deposition on soils and receiving bodies of water; and other effects associated with secondary aerosol formation. The modeling approach for addressing impacts of the proposed project on AQRVs in the Class I areas and the Class II Wilderness area is described in Section 7 of this application.

In addition to these Class I analyses, per direction of the United States Forest Service (USFS) (USFS, 2010, *email from Rick Graw (USFS) to Christy Schmitt (URS)*, June 11), analyses for visibility, growth impacts, and impacts to soils and vegetation at the Alpine Lakes Wilderness (ALW, a Class I area located just over 100 km from the Project site) and Mt. Baker Wilderness Area (MTB, a Class II protected area located approximately 41 km from the Project site) were also conducted.

Visual impacts to Class I areas must also be considered for project permitting. Visibility impairment is defined in WAC 173-400-030-91 as "any humanly perceptible change in visibility (light extinction, visual range, contrast, or coloration) from that which would have existed under natural conditions". In addition, a cumulative impact study that assesses the impacts from multiple sites in the area may be required if the visibility impact of the proposed source is greater than a 5 percent change in extinction. As will be shown in Section 7 of this application, the visibility impacts for the PSE Fredonia Project are expected to be minimal, and a cumulative impact analysis is not required.

4.5 TOXIC AIR POLLUTANTS

The proposed Project also has the potential to emit toxic/hazardous non-criteria air pollutants. These are regulated by EPA as HAPs under Clean Air Act (CAA) Section 112, and by Ecology as TAPs under WAC 173-460. Ecology also has a NSR requirement for TAP sources (WAC 173-460-040); an analysis must indicate that the proposed project is in compliance with ASILs. Section 3.4, above, described the emission estimates for TAPs and HAPs, and Table 3-6 shows the TAPs that required further analysis to show compliance with NSR. The modeling analyses used to demonstrate compliance with ASILs is shown in Section 8 of this application.

5.1 INTRODUCTION

As discussed in Section 4.1.1 above, a BACT analysis is required as part of the PSD process. Estimated Project emissions (see Table 3-1), trigger PSD BACT for:

- $PM/PM_{10}/PM_{2.5}$ for each of the four proposed gas turbine options
- H_2SO_4 mist for each of the four proposed gas turbine options,
- CO for the Siemens turbine option only, and
- GHG for each of the four proposed gas turbine options.

NWCAA NOC permitting also requires a BACT analysis for NO_x, CO, SO_2, and VOC. Thus, all of these pollutants are addressed in this section.

40 CFR 51.21(j) defines BACT as emission limits "based on maximum degree of reduction for each pollutant." BACT determinations are made on a case-by-case basis, taking into account energy, environmental, and economic impacts, and other costs.

BACT requirements may be more stringent, but not less stringent than other applicable emission standards. General standards for maximum emissions for air pollution sources in Washington are outlined in WAC 173-400-040. Compliance with these general state and local emission standards is addressed below. More stringent federal NSPS for specific source types are also implemented in Ecology rules; applicable NSPS emission limits are identified in Section 4.1.2 of this application, and compliance is also addressed in that section.

Three air emission source types are proposed for this project:

- Simple cycle gas turbine generator(s), for which four equipment options are being considered by PSE:
  - One GE 7FA.05 frame turbine;
  - One GE 7FA.04 frame turbine;
  - One Siemens SGT6-5000F4 frame turbine; or
  - Two GE LMS 100 aeroderivative turbines.
- A 600 kW emergency generator (Caterpillar with Model C18 ATAAC Tier 2 engine (approximately 890 brake-horsepower (bhp)), or similar make and model).
- Substation breakers containing SF_6.

Most of the following section addresses BACT for the gas turbines because they are the primary source of emissions for the proposed project. BACT for the pollutants subject to PSD is addressed in Section 5.3. BACT for other criteria pollutants, subject to regulation by Washington's NOC permitting program, is discussed in Section 5.5. Washington regulations also require BACT to control toxic air pollutants (tBACT), which is addressed in Section 5.6. The Project's other source of emissions is the emergency generator. BACT for the generator is addressed in Section 5.4.

5.2 BACT ASSESSMENT METHODOLOGY

In a December 1, 1987 memorandum from the EPA Assistant Administrator for Air and Radiation, the agency recommended use of a “top-down” methodology for determining BACT. This top-down BACT analysis process consists of five steps (from the EPA’s *Draft New Source Review Workshop Manual*, 1990):

Step 1. Identify all available control technologies with practical potential for application to the specific emission unit for the regulated pollutant under evaluation;

Step 2. Eliminate all technically infeasible control technologies;

Step 3. Rank remaining control technologies by control effectiveness and tabulate a control hierarchy;

Step 4. Evaluate most effective controls and document results; and

Step 5. Select BACT, which will be the most effective practical option not rejected, based on economic, environmental, and/or energy impacts.

If the applicant proposes to implement the most effective or "top" available control strategy, Step 4 is not necessary. During PSE’s June 16, 2010 preapplication meeting with Ecology and NWCAA staff, it was agreed that PSE’s BACT analysis would rely on recent relevant BACT determinations to identify the top current control levels achieved in practice.

Three sources were reviewed to identify relevant BACT determinations for simple cycle gas turbines in the past 5 years (2006 to date):

- EPA’s RACT/BACT/LAER Clearinghouse (RBLC),
- California Air Resources Board (CARB) BACT Clearinghouse, and
- Information for California Energy Commission power plant siting cases, including local air quality management district findings.

Because BACT determinations generally become increasingly stringent as emission control technology and operating experience improve over time, only projects that were approved in 2006 to date were included in this analysis.

5.2.1 EPA RBLC

BACT determinations identified in the RBLC for large utility-scale simple cycle industrial gas turbine generator units since 2006 are listed in Table 5-1. The RBLC contains a wide range of BACT emission limitations. Table 5-2 summarizes the ranges of BACT emission limits found in the RBLC for NO_x, CO, and VOC for both fuel types. BACT control methods for $PM/PM_{10}/PM_{2.5}$, SO_2, and H_2SO_4 mist in the RBLC are the use of 1) natural gas as the primary fuel and 2) good combustion practices. Mass emission limits for $PM/PM_{10}/PM_{2.5}$, SO_2 and H_2SO_4 mist are case-specific, and depend upon turbine make and model, site conditions and locally available fuel characteristics. No top-down BACT determinations were found in the RBLC for simple cycle start-ups and shutdowns. Likewise, no BACT determinations were found for GHGs.

Table 5-1
Summary of RBLC BACT Determinations for Utility-Scale Simple Cycle Gas Turbines (2006 to date)

RBLC ID	Permit Issue Date	Company	Location County, State	System Description	Production Rate	PRIMARY FUEL	POLLUTANT	CONTROL METHOD	EMISSION LIMIT	AVG. TIME (HR)	CASE-BY-CASE BASIS
CA-1174	12/11/2009	EL CAJON ENERGY LLC	SAN DIEGO, CA	Gas turbine simple cycle	49.95 MW	NATURAL GAS	Nitrogen Oxides (NOx)	Water injection and SCR	2.5 PPMV	1	BACT-PSD
							Volatile Organic Compounds (VOC)	Oxydation catalyst	2 PPMV	1	BACT-PSD
CO-0064	8/31/2007	PLATTE RIVER POWER AUTHORITY	LARIMER, CO	UNIT F COMBUSTION TURBINE	1400 MMBTU/H	NATURAL GAS	Nitrogen Oxides (NOx)	DRY LOW NOX COMBUSTION SYSTEM	9 PPMVD @ 15% O2	3	BACT-PSD
							Particulate Matter (PM)	USE OF PIPELINE QUALITY NATURAL GAS			
							Particulate Matter (PM)	USE OF PIPELINE QUALITY NATURAL GAS			
FL-0285	1/26/2007	PROGRESS ENERGY FLORIDA (PEF)	PINELLAS, FL	SIMPLE CYCLE COMBUSTION TURBINE (ONE UNIT)	1972 MMBTU/H	NATURAL GAS	Carbon Monoxide	GOOD COMBUSTION	4.1 PPMVD @ 15% O2		BACT-PSD
							Nitrogen Oxides (NOx)	WATER INJECTION DRY LOW NOX	15 PPMVD	4	BACT-PSD
							Sulfur Dioxide (SO2)	USE OF PIPELINE QUALITY NATURAL GAS			
							Volatile Organic Compounds (VOC)	GOOD COMBUSTION	1.2 PPMVD @ 15% O2 (N. GAS)		BACT-PSD
					1876 MMBTU/H	FUEL OIL	Carbon Monoxide	GOOD COMBUSTION	8 PPMVD (OIL)		BACT-PSD

Table 5-1
Summary of RBLC BACT Determinations for Utility-Scale Simple Cycle Gas Turbines (2006 to date)

RBLC ID	Permit Issue Date	Company	Location County, State	System Description	Production Rate	PRIMARY FUEL	POLLUTANT	CONTROL METHOD	EMISSION LIMIT	AVG. TIME (HR)	CASE-BY-CASE BASIS
							Nitrogen Oxides (NOx)	WATER INJECTION DRY LOW NOX	42 PPMVD (OIL)	4	BACT-PSD
							Sulfur Dioxide (SO2)	NATURAL GAS AS PRIMARY FUEL WITH 0.05% SULFUR FUEL OIL DISTILLATE AS BACK UP.	0.05 %S		BACT-PSD
							Volatile Organic Compounds (VOC)	GOOD COMBUSTION PRACTICES	2.8 PPMVD@15 % O2 (OIL)		BACT-PSD
FL-0287	11/17/2006	OLEANDER POWER PROJECT, L.P	BREVARD, FL	SIMPLE CYCLE COMBUSTION TURBINE	190 MW	NATURAL GAS	Nitrogen Oxides (NOx)	DLN COMBUSTORS WATER INJECTION	9 PPM @ 15% O2 (N. GAS)	24	BACT-PSD
							Particulate matter, filterable < 10 µ (FPM10)	CLEAN FUELS			
							Sulfur Dioxide (SO2)	USE OF PIPELINE QUALITY NATURAL GAS			
						FUEL OIL	Nitrogen Oxides (NOx)	DLN COMBUSTORS WATER INJECTION	42 PPM @ 15% O2 (OIL)	4	BACT-PSD
							Particulate matter, filterable < 10 µ (FPM10)	GOOD COMBUSTION PRACTICES, ULTRA LOW SULFUR DISTILLATE FUEL			BACT-PSD

Table 5-1
Summary of RBLC BACT Determinations for Utility-Scale Simple Cycle Gas Turbines (2006 to date)

RBLC ID	Permit Issue Date	Company	Location County, State	System Description	Production Rate	PRIMARY FUEL	POLLUTANT	CONTROL METHOD	EMISSION LIMIT	AVG. TIME (HR)	CASE-BY-CASE BASIS
							Sulfur Dioxide (SO2)	NATURAL GAS AS PRIMARY FUEL WITH 0.05% SULFUR FUEL OIL DISTILLATE AS BACK UP. USES WATER INJECTION WHEN FIRING OIL.	0.05 %S		BACT-PSD
FL-0300	12/22/2006	JACKSON-VILLE ELECTRIC AUTHORITY	DUVAL, FL	SIMPLE CYCLE TURBINE 172 MW	1804 MMBTU/H	NATURAL GAS	Nitrogen Oxides (NOx)	NATURAL GAS AS PRIMARY FUEL WITH 0.05% SULFUR DISTILLATE AS BACKUP. USES WATER INJECTION WHEN FIRING OIL.	15 PPM @ 15% 02 (N. GAS)	4	Other Case-by-Case
							Sulfur Dioxide (SO2)	NATURAL GAS AS PRIMARY FUEL			
						FUEL OIL	Nitrogen Oxides (NOx)	NATURAL GAS AS PRIMARY FUEL WITH 0.05% SULFUR DISTILLATE AS BACKUP. USES WATER INJECTION WHEN FIRING OIL.	42 PPM @ 15% 02 (OIL)	4	Other Case-by-Case
							Sulfur Dioxide (SO2)	NATURAL GAS AS PRIMARY FUEL WITH 0.05% SULFUR FUEL OIL DISTILLATE AS	0.05 %S		Other Case-by-Case

Table 5-1
Summary of RBLC BACT Determinations for Utility-Scale Simple Cycle Gas Turbines (2006 to date)

RBLC ID	Permit Issue Date	Company	Location County, State	System Description	Production Rate	PRIMARY FUEL	POLLUTANT	CONTROL METHOD	EMISSION LIMIT	AVG. TIME (HR)	CASE-BY-CASE BASIS
								BACK UP. USES WATER INJECTION WHEN FIRING OIL.			
FL-0310	1/12/2009	SHADY HILLS POWER COMPANY	PASCO, FL	TWO SIMPLE CYCLE COMBUSTION TURBINE - MODEL 7FA	170 MW	NATURAL GAS	Carbon Monoxide		6.5 PPMVD @ 15% O2 (N. GAS)		BACT-PSD
							Nitrogen Oxides (NOx)	FIRING NATURAL GAS AND USING DLN 2.6 COMBUSTORS TO MINIMIZE NOX EMISSSIONS.	9 PPMVD @ 15% O2	24	BACT-PSD
							Particulate matter, total < 10 µ (TPM10)	THE SULFUR FUEL SPECIFICTIONS COMBINED WITH THE EFFICIENT COMBUSTION DESIGN AND OPERATION OF THE CT WILL MINIMIZE PM/PM10 EMISSIONS. COMPLIANCE WITH THE FUEL SPECIFICATION, CO STANDARDS, AND VISIBLE EMISSIONS STANDARDS SHALL SERVE AS	10 % OPACITY	6 MIN.	BACT-PSD

Table 5-1
Summary of RBLC BACT Determinations for Utility-Scale Simple Cycle Gas Turbines (2006 to date)

RBLC ID	Permit Issue Date	Company	Location County, State	System Description	Production Rate	PRIMARY FUEL	POLLUTANT	CONTROL METHOD	EMISSION LIMIT	AVG. TIME (HR)	CASE-BY-CASE BASIS
								INDICATORS OF GOOD COMBUSTION.			
							Sulfur Dioxide (SO2)	USE OF PIPELINE QUALITY NATURAL GAS			
						FUEL OIL	Carbon Monoxide		13.5 PPMVD @ 15% O2		
							Sulfur Dioxide (SO2)	ULTRA LOW SULFUR DIESEL FUEL OIL WITH A MAXIMUM S CONTENT AT 0.0015%, BY WEIGHT.	0.0015 %S		BACT-PSD
GA-0139	5/14/2010	SOUTHERN POWER COMPANY	JACKSON, GA	SIMPLE CYCLE COMBUSTION TURBINE - ELECTRIC GENERATING PLANT	1530 MW	NATURAL GAS	Carbon Monoxide	GOOD COMBUSTION PRACTICES	9 PPM @15% 02	3	BACT-PSD
							Nitrogen Oxides (NOx)	DRY LOW NOX BURNERS (FIRING NATURAL GAS). WATER INJECTION	9 PPM @ 15% 02	3	BACT-PSD

Table 5-1
Summary of RBLC BACT Determinations for Utility-Scale Simple Cycle Gas Turbines (2006 to date)

RBLC ID	Permit Issue Date	Company	Location County, State	System Description	Production Rate	PRIMARY FUEL	POLLUTANT	CONTROL METHOD	EMISSION LIMIT	AVG. TIME (HR)	CASE-BY-CASE BASIS
								(FIRING FUEL OIL).			
							Particulate matter, total < 10 µ (TPM10)	GOOD COMBUSTION PRACTICES PIPELINE QUALITY NATURAL GAS			
							Volatile Organic Compounds (VOC)	GOOD COMBUSTION PRACTICES	5 PPM @ 15% 02	3	BACT-PSD
						FUEL OIL	Carbon Monoxide	GOOD COMBUSTION PRACTICES	30 PPM @ 15% 02	3	BACT-PSD
							Nitrogen Oxides (NOx)	DRY LOW NOx BURNERS (FIRING NATURAL GAS), WATER INJECTION (FIRING FUEL OIL).	42 PPM @ 15% 02	3	BACT-PSD
							Particulate matter, total < 10 µ (TPM10)	GOOD COMBUSTION PRACTICES, ULTRA LOW SULFUR DISTILLATE FUEL			
							Volatile Organic Compounds (VOC)	GOOD COMBUSTION PRACTICES	5 PPM @ 15% 02	3	BACT-PSD
MN-0075	7/1/2008	GREAT RIVER	SHERBURNE, MN	COMBUSTION TURBINE	2169 MMBTU/H	NATURAL GAS	Carbon Monoxide	GOOD COMBUSTION	4 PPM (>/= 70% LOAD)	4	BACT-PSD

Table 5-1
Summary of RBLC BACT Determinations for Utility-Scale Simple Cycle Gas Turbines (2006 to date)

RBLC ID	Permit Issue Date	Company	Location County, State	System Description	Production Rate	PRIMARY FUEL	POLLUTANT	CONTROL METHOD	EMISSION LIMIT	AVG. TIME (HR)	CASE-BY-CASE BASIS
		ENERGY		GENERATOR				PRACTICES	10 PPM (60% - 70% LOAD)	4	BACT-PSD
									150 PPM (<60% (LOAD)	4	BACT-PSD
							Nitrogen Oxides (NOx)	DRY LOW-NOX COMBUSTION WHEN COMBUSTING NATURAL GAS	9 PPM (>/= 60% LOAD)	4	BACT-PSD
									25 PPM (<60% LOAD)	4	BACT-PSD
							Particulate Matter (PM)	FUEL LIMITED TO NATURAL GAS AND ULTRA-LOW SULFUR FUEL OIL	NO EMISSION LIMITS		
						FUEL OIL	Carbon Monoxide	GOOD COMBUSTION PRACTICES	10 PPM (>/= 70% LOAD)	4	BACT-PSD
									250 PPM (OIL @ 60% - 70% LOAD)	4	BACT-PSD
									600 PPM (OIL @ <60% LOAD)	4	BACT-PSD
							Nitrogen Oxides (NOx)	WATER INJECTION WHEN COMBUSTING FUEL OIL	42 PPM (OIL @ >/= 70% LOAD)	4	BACT-PSD
									50 PPM (OIL @ <70% LOAD)	4	BACT-PSD
NJ-0075 draft	9/24/2009	BAYONNE ENERGY CENTER, LLC	HUDSON, NJ	15.100 - SIMPLE CYCLE	603 MMBTU/H	NATURAL GAS	Carbon Monoxide	CO OXIDATION CATALYST AND CLEAN BURNING FUELS	5 PPMVD @ 15%O2		OTHER CASE-B
							Nitrogen Oxides (NOx)	SELECTIVE CATALYTIC REDUCTION	2.5 PPMVD @ 15%O2		LAER

Table 5-1
Summary of RBLC BACT Determinations for Utility-Scale Simple Cycle Gas Turbines (2006 to date)

RBLC ID	Permit Issue Date	Company	Location County, State	System Description	Production Rate	PRIMARY FUEL	POLLUTANT	CONTROL METHOD	EMISSION LIMIT	AVG. TIME (HR)	CASE-BY-CASE BASIS
								SYSTEM (SCR) AND WET LOW-EMISSION (WLE) COMBUSTORS			
							Particulate matter, filterable < 10 µ (FPM10) and PM, filterable < 2.5 µ (FPM2.5)	BURNING CLEAN FUELS, NATURAL GAS AND ULTRA LOW SULFUR DISTILLATE OIL WITH SULFUR CONTENT OF 15 PPM (0.0015%) BY WEIGHT SULFUR			
							Sulfur Dioxide (SO2)	BURNING CLEAN FUELS, NATURAL GAS			
							Volatile Organic Compounds (VOC)	CO OXIDATION CATALYST AND POLLUTION PREVENTION, BURNING CLEAN FUELS, NATURAL GAS	2.5 PPMVD @ 15%O2		LAER
					538 MMBTU/H	FUEL OIL	Carbon Monoxide	GOOD ENGINEERING PRACTICES	5 PPMVD @ 15%O2		
							Sulfur Dioxide (SO2)	BURNING CLEAN FUELS, NATURAL GAS AND ULTRA LOW SULFUR DISTILLATE OIL WITH SULFUR CONTENT OF 15 PERCENT BY WEIGHT			

Table 5-1
Summary of RBLC BACT Determinations for Utility-Scale Simple Cycle Gas Turbines (2006 to date)

RBLC ID	Permit Issue Date	Company	Location County, State	System Description	Production Rate	PRIMARY FUEL	POLLUTANT	CONTROL METHOD	EMISSION LIMIT	AVG. TIME (HR)	CASE-BY-CASE BASIS
								SULFUR			
							Nitrogen Oxides (NOx)		5 PPMVD @ 15%O2		
NV-0046	5/16/2006	KERN RIVER GAS TRANSMISSION COMPANY	CLARK, NV	LARGE COMBUSTION TURBINE - SIMPLE CYCLE	97.81 MMBTU/H	NATURAL GAS	Carbon Monoxide	GOOD COMBUSTION PRACTICE	16 PPMVD @ 15% o2	3 MONTH	BACT-PSD
							Nitrogen Oxides (NOx)	THE SOLONOX BURNER IN EACH TURBINE UTILIZES THE DRY LOW-NOX TECHNOLOGY TO CONTROL NOX EMISSIONS.	25 PPMVD @ 15% O2		BACT-PSD
							Particulate matter, filterable < 10 µ (FPM10)	NATURAL GAS IS THE ONLY FUEL FOR THE PROCESS.			
							Sulfur Dioxide (SO2)	NATURAL GAS IS THE ONLY FUEL FOR THE PROCESS.			
							Volatile Organic Compounds (VOC)	GOOD COMBUSTION PRACTICE			
OH-0253	3/7/2006	DAYTON POWER AND LIGHT	MONTGOMERY, OH	COMBUSTION TURBINE (1), SIMPLE	1115 MMBTU/H	NATURAL GAS	Carbon Monoxide	GOOD COMBUSTION PRACTICE			

Table 5-1
Summary of RBLC BACT Determinations for Utility-Scale Simple Cycle Gas Turbines (2006 to date)

RBLC ID	Permit Issue Date	Company	Location County, State	System Description	Production Rate	PRIMARY FUEL	POLLUTANT	CONTROL METHOD	EMISSION LIMIT	AVG. TIME (HR)	CASE-BY-CASE BASIS
		COMPANY		CYCLE			Nitrogen Oxides (NOx)	DRY LOW NOX burners	15 PPM @ 15% O2 (N. GAS @ FULL LOAD)		BACT-PSD
							Particulate matter, filterable < 10 µ (FPM10)	USE OF PIPELINE QUALITY NATURAL GAS			
							Sulfur Dioxide (SO2)	USE OF PIPELINE QUALITY NATURAL GAS			
							Volatile Organic Compounds (VOC)	GOOD COMBUSTION PRACTICE			
					1115 MMBTU/H	FUEL OIL	Carbon Monoxide	GOOD ENGINEERING PRACTICES			
							Nitrogen Oxides (NOx)	WATER INJECTION	42 PPM @ 15% O2 (OIL @ FULL LOAD)		BACT-PSD
							Particulate matter, filterable < 10 µ (FPM10)	GOOD COMBUSTION PRACTICES, ULTRA LOW SULFUR DISTILLATE FUEL			
							Sulfur Dioxide (SO2)	LOW SULFUR FUEL (0.05% BY WEIGHT SULFUR IN OIL)			
							Volatile Organic Compounds (VOC)	GOOD COMBUSTION PRACTICE			

Table 5-1
Summary of RBLC BACT Determinations for Utility-Scale Simple Cycle Gas Turbines (2006 to date)

RBLC ID	Permit Issue Date	Company	Location County, State	System Description	Production Rate	PRIMARY FUEL	POLLUTANT	CONTROL METHOD	EMISSION LIMIT	AVG. TIME (HR)	CASE-BY-CASE BASIS
				COMBUSTION TURBINES (2), SIMPLE CYCLE	1115 MMBTU/H	NATURAL GAS	Carbon Monoxide	GOOD ENGINEERING PRACTICES			
							Nitrogen Oxides (NOx)	DRY LOW NOX burners	25 PPM @ 15% O2 (N. GAS @ FULL LOAD)		BACT-PSD
							Particulate matter, filterable < 10 µ (FPM10)	USE OF PIPELINE QUALITY NATURAL GAS			
							Sulfur Dioxide (SO2)	USE OF PIPELINE QUALITY NATURAL GAS			
							Volatile Organic Compounds (VOC)	GOOD COMBUSTION PRACTICE			
					1115 MMBTU/H	FUEL OIL	Carbon Monoxide	GOOD ENGINEERING PRACTICES			
							Nitrogen Oxides (NOx)	WATER INJECTION	42 PPM @ 15% O2 (OIL @ FULL LOAD)		BACT-PSD
							Particulate matter, filterable < 10 µ (FPM10)	LOW SULFUR FUEL (0.05% BY WEIGHT SULFUR IN OIL)			
							Sulfur Dioxide (SO2)	LOW SULFUR FUEL (0.05% BY WEIGHT SULFUR IN OIL)			OTHER CASE-BY-CASE
							Volatile Organic Compounds (VOC)	GOOD COMBUSTION PRACTICE			

Table 5-1
Summary of RBLC BACT Determinations for Utility-Scale Simple Cycle Gas Turbines (2006 to date)

RBLC ID	Permit Issue Date	Company	Location County, State	System Description	Production Rate	PRIMARY FUEL	POLLUTANT	CONTROL METHOD	EMISSION LIMIT	AVG. TIME (HR)	CASE-BY-CASE BASIS
OH-0304	1/17/2006	ROLLING HILLS GENERATING, LLC	VINTON, OH	NATURAL GAS FIRED TURBINES (5)	209 MW	NATURAL GAS	Carbon Monoxide	GOOD ENGINEERING PRACTICES			
							Nitrogen Oxides (NOx)	DRY LOW NOX BURNERS	15 PPMVD @ 15% O2		BACT-PSD
							Particulate matter, filterable < 10 µ (FPM10)	USE OF PIPELINE QUALITY NATURAL GAS			
							Sulfur Dioxide (SO2)	USE OF PIPELINE QUALITY NATURAL GAS			
							Volatile Organic Compounds (VOC)	GOOD COMBUSTION PRACTICE			
OH-0333	12/3/2009	DAYTON POWER & LIGHT COMPANY	MONTGOMERY, OH	Turbines (4), simple cycle, natural gas	15020 H/YR	NATURAL GAS	Carbon Monoxide	efficient combustion technology	20 PPMVD @ 15% O2	3	BACT-PSD
							Nitrogen Oxides (NOx)	dry low NOx burners	15 PPMVD @ 15% O2	1	BACT-PSD
							Particulate matter, filterable (FPM), PM, filterable < 10 µ (FPM10) and PM, filterable < 2.5 µ (FPM2.5)	using only clean fuels, natural gas or #2 fuel oil.			
							Sulfur Dioxide (SO2)	USE OF PIPELINE QUALITY			

Table 5-1
Summary of RBLC BACT Determinations for Utility-Scale Simple Cycle Gas Turbines (2006 to date)

RBLC ID	Permit Issue Date	Company	Location County, State	System Description	Production Rate	PRIMARY FUEL	POLLUTANT	CONTROL METHOD	EMISSION LIMIT	AVG. TIME (HR)	CASE-BY-CASE BASIS
								NATURAL GAS			
				Turbines (4), simple cycle, fuel oil #2	4216 H/YR	Fuel oil #2	Carbon Monoxide	efficient combustion technology	20 PPMVD @ 15% O2	3	BACT-PSD
							Nitrogen Oxides (NOx)	Water injection	42 PPMVD @ 15% O2	1	BACT-PSD
							Particulate matter, filterable (FPM), PM, filterable < 10 µ (FPM10) and PM, filterable < 2.5 µ (FPM2.5)	using only clean fuels, natural gas or #2 fuel oil.			
							Sulfur Dioxide (SO2)	Fuel oil with no more than 0.05% by weight sulfur			
							Volatile Organic Compounds (VOC)	GOOD COMBUSTION PRACTICE			
OK-0120	3/22/2007	PUBLIC SERVICE CO OF OKLAHOMA	TULSA, OK	COMBUSTION TURBINES			Carbon Monoxide	GOOD COMBUSTION PRACTICES & DESIGN			
							Nitrogen Oxides (NOx)	DRY-LOW NOX BURNERS	9 PMVDD @ 15% O2		BACT-PSD
							Particulate matter, filterable < 10 µ (FPM10)	GOOD COMBUSTION PRACTICES IN COMBINATION WITH THE USE OF LOW-ASH FUEL			

Table 5-1
Summary of RBLC BACT Determinations for Utility-Scale Simple Cycle Gas Turbines (2006 to date)

RBLC ID	Permit Issue Date	Company	Location County, State	System Description	Production Rate	PRIMARY FUEL	POLLUTANT	CONTROL METHOD	EMISSION LIMIT	AVG. TIME (HR)	CASE-BY-CASE BASIS
OK-0127	6/13/2008	WESTERN FARMERS ELECTRIC COOP.	CADDO, OK	COMBUSTION TURBINE PEAKING UNIT(S)	462.7 MMBTU/H	NATURAL GAS	Carbon Monoxide	GOOD COMBUSTION PRACTICES	63 PPM @ 15% O2		BACT-PSD
							Nitrogen Oxides (NOx)	WATER INJECTION	25 PPM @ 15% O2		BACT-PSD
							Particulate matter, filterable < 10 µ (FPM10)	GOOD COMBUSTION PRACTICES IN COMBINATION WITH USE OF NATURAL GAS			
WI-0240	1/26/2006	WISCONSIN ELECTRIC POWER	JEFFERSON, WI	COMBUSTION TURBINE, 100 MW, NATURAL GAS	100 MW	NATURAL GAS	Carbon Monoxide	GOOD COMBUSTION PRACTICES			
							Nitrogen Oxides (NOx)	WATER INJECTION	25 PPMDV @ 15% O2		BACT-PSD
							Particulate Matter (PM)	USE OF PIPELINE QUALITY NATURAL GAS			
							Sulfur Dioxide (SO2)	USE ONLY NATURAL GAS			
							Volatile Organic Compounds (VOC)	GOOD COMBUSTION PRACTICE			
				COMBUSTION TURBINE, 100 MW, #2 FUEL OIL		#2 FUEL OIL	Nitrogen Oxides (NOx)	WATER INJECTION	65 PPMDV @ 15% O2		BACT-PSD
							Sulfur Dioxide (SO2)	USE ONLY 0.05% S #2 OIL			

Table 5-2
Summary of Relevant Recent BACT Determinations
In EPA's RACT/BACT/LAER Clearinghouse

Pollutant	BACT RANGE (ppm) from RACT/BACT/LAER Clearinghouse Database for Years 2006-2010 Simple Cycle Turbines	
	NATURAL GAS	FUEL OIL
Nitrogen Dioxide (NO_x)	2.5-25	5-65
Carbon Monoxide (CO)	4-63	5-30
Volatile Organic Compounds (VOC)	1.2-5	2.8-5
$PM_{2.5}$/PM_{10}, Sulfur Dioxide (SO_2) and Sulfuric Acid Mist (H_2SO_4)	Locally Available Pipeline	0.0015-0.5% sulfur content by weight in fuel[1]
Greenhouse Gases (GHG)	NA	NA

[1] Ultra-low sulfur fuel oil (ULSD) = 0.0015% S by weight.

5.2.2 California BACT Determinations

In addition to evaluating BACT determinations reported in the RBLC, California BACT determinations listed in the CARB Clearinghouse and California Energy Commission (CEC) permitting information were evaluated. California BACT determinations are often more stringent than decisions from other states because California's BACT definition is equivalent to federal Lowest Achievable Emission Rate (LAER) requirements, which does not consider the economic feasibility of control options.

The CARB BACT Clearinghouse was reviewed. This database is no longer regularly updated. The last BACT determination entered into the clearinghouse for utility-scale simple cycle gas turbine was dated 1999. These determinations are considered outdated.

A well-documented source of recent power plant permitting information is the CEC. In California, any new power plant unit similar in size to PSE's proposed project must be certified by the CEC prior to construction. The CEC's power plant siting case list was reviewed to identify similar large utility-scale simple cycle gas turbine power projects (current and past CEC certification projects are summarized at http://www.energy.ca.gov/sitingcases/all_projects.html#approved). Air permits to construct for each identified siting case were reviewed to identify BACT emission limitations. California BACT determinations are summarized in Table 5-3. Six units in this table are similar to the PSE turbine options: two frame-sized engines (one Siemens SGT6-5000F4 and one GE F7A.03), and four GE LMS100 projects. The remaining five BACT determinations in Table 5-3 are for smaller, GE LM6000 and Pratt & Whitney FT8-3, gas turbine projects. Two projects in this table have not received full CEC approval to date, but the regional air districts have performed BACT review. BACT determinations listed in Table 5-3 are at least as stringent and in many cases, more stringent than the RBLC-listed BACT determinations in Table 5-1. To date, no PSD BACT determinations have been completed for GHG emissions from simple cycle gas turbines in California.

Table 5-3
Recent California BACT Determinations for Similar Simple Cycle Gas Turbines

Facility Information	Permit Approval Date	Project Status	BACT Emission Limit (ppmvd @ 15% O_2) NOx	CO	VOC	Start-up Shutdown Top-Down	BACT Limit GHG
Frame Turbines similar in size and operation to PSE Fredonia Expansion Project Frame Turbine							
Marsh Landing Generating Station, Siemens SGT6-5000F Gas Turbine, 190 MW (BAAQMD)	8/25/2010	Approved	2.5 (1-hr)[1]	2 (1-hr)	2 (1-hr)	No	NA
Pastoria Energy Facility Expansion Project, GE Frame 7FA 160 MW (SJVAPCD)	12/18/2006	Approved; construction on hold	2.5 (1-hr)	6 (3-hr)	1.3 (3-hr)	No	NA
Aeroderivative Turbines similar in size and operation to PSE Fredonia Expansion Project GE LMS100							
CPV Sentinal Energy Project, GE LMS100 Gas Turbine, 100 MW (SCAQMD)	8/25/2010	Approved	2.5 (1-hr)	6 (1-hr)	2 (1-hr)	No	NA
Walnut Creek Energy Park, GE LMS100 Gas Turbine, 100 MW (SCAQMD)	2/27/2008	Approved; construction on hold	2.5 (1-hr)	6 (1-hr)	2 (1-hr)	No	NA
Panoche Energy Center, GE LMS100 Gas Turbine, 100 MW (SJVAPCD)	12/19/2007	Operational	2.5 (1-hr)	6 (3-hr)	2 (3-hr)	No	NA
Sun Valley Energy Project, GE LMS100 Gas Turbine, 100 MW (SCAQMD)[2]	Application filed in 2005; CEC review terminated 2011	Preliminary approval	2.5 (1-hr)	6 (1-hr)	2 (1-hr)	No	NA
Additional Smaller Turbines							
Mariposa Energy Project, GE LM6000 Gas Turbines, 200 MW total (BAAQMD)	CEC Review in Progress	Final BACT review by BAAQMD	2.5 (1-hr)	2 (3-hr)	1 (1-hr)	No	NA
Almond 2 Power Plant (PDOC only), GE LM6000PG Gas Turbines, 54.2 MW (SJVACPD)	12/15/2010	Approved	2.5 (1-hr)	4.0 (3-hr)	2 (3-hr)	No	NA
Canyon Power Plant (PDOC only), GE LM6000PC, 200 MW Total (BAAQMD)	3/17/2010	Under Construction	2.5 (1 hr); 2.3 proposed by applicant	6 (1-hr)	2 (1-hr)	No	NA
Starwood Power-Midway, PW FT8-3 SwiftPac, 60 MW (SJVACPD)	1/16/2008	Operational	2.5 (1-hr)	BACT not required	2 (3-hr)	No	NA
San Francisco Electric Reliability Project, GE LM6000 Gas Turbines, 49 MW (BAAQMD)	10/3/2006	Approved; construction on hold	2.5 (1-hr)	4 (3-hr)	2 (1-hr)	No	NA

Source: CEC, along with BAAQMD, SCAQMD, and SJVAPCD; determinations for large utility-scale simple cycle gas turbine power plants, 2005 to date (http://www.energy.ca.gov/sitingcases/all_projects.html#approved). For this subset of projects on the CEC's current list, BACT determinations within three California air quality management districts were reviewed for PSE's BACT assessment: the Bay Area Air Quality Management District (BAAQMD), San Joaquin Valley Air Pollution Control District (SJVAPCD), and South Coast Air Quality Management District (SCAQMD). These three Districts are reasonably representative of permit requirements in California. BACT determinations in other air districts are likely the same or less stringent.

1 The 2.5 parts per million by volume dry (ppmvd) @ 15% O_2 NO_x emission limit for Marsh Landing is a 1-hr average during stable load periods, and a 3-hr average during load transition periods.

2 Sun Valley Energy Project was included in a recent BAAQMD BACT review for the Marsh Landing Generating Station. However, permit status is unknown, and the final approval to construct has not been issued by the CEC.

NA = GHG was not an applicable PSD pollutant for projects in this table. All were permitted prior to January 2011..

No top-down BACT analyses for turbine start-ups and shutdowns were found in agency permitting documents for the facility permits in Table 5-3. Duration and mass emission limits are commonly issued for gas turbines, which are sometimes identified as BACT limits; however, these limits are project specific and are not tied to top-down analysis.

5.3 BACT FOR PSD POLLUTANTS FROM GAS TURBINES AND SWITCHYARD BREAKERS

As explained above, the pollutants subject to PSD are PM, PM_{10}, $PM_{2.5}$, CO (Siemens turbine only), H_2SO_4, and GHGs. Each is addressed in turn.

With regard to gas turbine emissions, this analysis focuses on steady-state emissions. As discussed above, no top-down BACT precedent has been found in RBLC and California permitting data sources for start-up and shutdown emissions. Duration and mass emission limits for start-ups and shutdowns in the reviewed permits and databases, although sometimes identified as BACT limits, are project specific. For a simple cycle project, the only available emission control method during startup (in addition from those already incorporated in the project) is the minimization of startup and shutdown times. In other words, for start-up, the equipment should be operated in a way that allows the ordinary performance of emission control technology to be achieved as quickly as possible, and for shutdown, the equipment should be operated in a way that reduces the period in which ordinary performance is not achieved. The project will use this "top" method, utilizing simple cycle turbines that are capable of starting up and shutting down quickly. All four turbines being proposed by the applicant start and shutdown quickly to minimize emissions. Proposed start-up and shutdown emission limits and durations are listed in Table 5-6 at the end of the BACT section.

5.3.1 PM, PM_{10} and $PM_{2.5}$

5.3.1.1 Step 1: Available Control Technologies

PM, PM_{10} and $PM_{2.5}$ are analyzed together because virtually all of the particulate matter emitted from the turbines will be 2.5 microns or smaller, and are referred to collectively as PM in this analysis. Available control technology options for PM emissions from the turbines are good combustion practices, and the use of fuels that have low ash and sulfur content. Fuel sulfur, when combusted, forms various sulfur oxides (SO_x), including SO_2 and H_2SO_4, that can react with other exhaust constituents (e.g., NH_3 from an SCR) to form condensable PM.

PM BACT determinations listed in Tables 5-2 and 5-3 are based fundamentally on the use of good combustion practices and locally available pipeline natural gas for simple cycle gas turbine power projects

5.3.1.2 Step 2: Eliminate Technically Infeasible Options

Using natural gas exclusively as the fuel for the Project is not technically feasible. PSE proposes to use natural gas whenever it is reasonably available. Natural gas is delivered locally to the FGS by the Cascade Natural Gas Company (Cascade) pipeline. PSE holds firm (365 days per year) pipeline capacity on Cascade’s immediately interconnected pipeline sufficient to operate this Project. Upstream of Cascade’s pipeline, the gas is delivered via Northwest Pipeline’s interstate pipeline. PSE holds a significant diversified portfolio of both firm and interruptible pipeline capacity on Northwest Pipeline which may be used to serve this Project. PSE intends to operate the Project with natural gas whenever capacity is reasonably available on the Northwest Pipeline.

Historically, there have been rare occasions when natural gas has not been reasonably available at the facility due to temporary Northwest Pipeline capacity limitations. In order to maintain a safe and reliable local/regional power grid and fulfill its obligation to serve its customers, PSE must be able to continue to operate the proposed generating unit(s) whenever their power is needed. ULSD will be used during what are expected to be very infrequent periods when natural gas is not reasonably available at the facility.

5.3.1.3 Steps 3-5: Rank Remaining Control Options, Evaluate and Select BACT

The top and only remaining control option for PM emissions is the primary use of natural gas and good combustion practices. PM emissions vary with operating conditions and the amount and type of fuel combusted. The maximum expected total PM stack emission rate from any of PSE's four combustion turbine options is about 0.0075 gr/dscf @ 7% O_2, including sulfates. Thus, the anticipated grain loading is well below the 0.05 gr/dscf allowed by the NWCAA emission standard.

5.3.2 BACT for CO (Siemens option only)

Of the equipment options considered by PSE, only the Siemens SGT6-5000F4 frame turbine would have potential CO emissions exceeding the SER and requiring PSD review.

5.3.2.1 Step 1: Available Control Technologies

Available control technology options for CO emissions from gas turbine engines are the use of 1) low CO emitting fuels, 2) good combustion practices and 3) add-on technology such as oxidation catalyst to oxidize CO in the gas turbine exhaust stream. CO emissions from gas turbines typically vary with operating conditions including turbine load and ambient temperature, and with fuel.

5.3.2.2 Step 2: Eliminate Technically Infeasible Options

Although the exclusive use of natural gas would reduce CO emissions, this is not a feasible option for the Project. As explained above, PSE has an obligation to serve its customers and must have the ability to use ultra-low sulfur diesel when natural gas is not reasonably available. PSE has, however, committed to using natural gas as fuel whenever it is reasonably available.

5.3.2.3 Steps 3-5: Rank Remaining Control Options, Evaluate and Select BACT

PSE proposes to use the most effective or top control option, an oxidation catalyst. An oxidation catalyst will reduce CO emissions to 4 ppmvd @ 15% O_2 or less when burning natural gas if the Siemens turbine option is selected. This is consistent with recent BACT determinations for natural gas-fired turbines.

During infrequent use of backup fuel oil, the Siemens turbine option will be typically capable of achieving 8 ppmvd CO at 15% O_2 or less; however during periods of low load operation, the Siemens option is estimated to reach levels as high as 12 ppmvd CO at 15% O_2. Specific controlled emission rates are provided in Attachment A and emission limits are listed in Table 5-6.

These CO emission concentrations are within the lower range of recent BACT determinations documented for fuel oil in the RBLC in Tables 5-1 and 5-2. Recent BACT determinations summarized in Tables 5-1, 5-2 and 5-3 range from as low as 2 ppmvd CO @ 15% O_2 to as high as 63 ppmvd CO @ 15% O_2 when operated on natural gas and as low as 5 ppmvd CO @ 15% O2 to as high as 30 ppmvd CO @ 15% O_2 when operated on fuel oil. For frame-sized turbines comparable to the Siemens SGT6-5000F4, however, BACT determinations have generally resulted in a limit of 6 ppmvd CO @ 15% O_2 when fired with natural gas. There are two exceptions. The Marsh Landing and Mariposa Energy projects have been permitted with a 2 ppmvd @ 15% O_2 limit, but those limits have not been achieved in practice. In fact, the District that permitted the Mariposa Energy facility stated that 2 ppm "is more stringent than what has been achieved in practice at other similar simple cycle facilities and is the most stringent limit that is technologically feasible and cost effective" (BAAQMD, *Final Determination of Compliance – Mariposa Energy Project*, November 2010). Other determinations for smaller engines (e.g., LM6000) are not considered to be representative of PSE's proposed larger frame-sized and LM100 turbine options because they have different emission characteristics.

5.3.3 BACT for H_2SO_4

5.3.3.1 Step 1: Available Control Technologies

H_2SO_4 mist emissions are the result of the oxidation of fuel sulfur during combustion. Additional oxidation also occurs at the oxidation catalyst. SO_2 is the dominant sulfur oxide formed in gas turbines, while a smaller amount of sulfur is oxidized to sulfur trioxide (SO_3), which combines with water vapor in the exhaust and in ambient air to form H_2SO_4 mist. Because H_2SO_4 also readily reacts with NH_3, SCR systems tend to help inhibit H_2SO_4 mist emissions.

None of the air permits reviewed for this analysis involved a BACT analysis for H_2SO_4 because emissions for the permitted facilities did not exceed the PSD SER. Available control technology options for H_2SO_4 mist emissions from gas turbines are 1) good combustion practices and 2) the use of fuels that have low sulfur content.

5.3.3.2 Step 2: Eliminate Technically Infeasible Options

As explained above, relying upon natural gas exclusively to fuel the Project is not a feasible option for PSE. PSE has, however, committed to using natural gas as fuel whenever it is reasonably available.

5.3.3.3 Steps 3-5: Rank Remaining Control Options, Evaluate and Select BACT

The applicant proposes to use the top or best technology to control H_2SO_4 mist, which is considered to be the use of 1) natural gas as the primary fuel for the Project together with 2) good combustion practices.

5.3.4 BACT for GHG

This topic is addressed in a stand-alone document titled *Greenhouse Gas BACT Analysis* (Submitted to Ecology and NWCAA, October 2011). The complete document is included as Attachment H of this Application.

5.4 BACT FOR EMERGENCY GENERATORS

As explained above, PSD BACT review is required for $PM/PM_{10}/PM_{2.5}$, H_2SO_4 mist and GHG for all project options, but for CO only if the Siemens turbine option is selected. The remaining pollutants are not subject to PSD BACT, but are subject to BACT for the NOC. For simplicity sake, no distinction between PSD and non-PSD is made for emergency generators in this analysis.

A diesel-fired generator is proposed as the only technically feasible option. A natural gas-fired generator technology is not a feasible option because there is a risk of significant damage to the gas turbine(s) and other power plant systems if a power grid outage occurred at the same time as a natural gas outage, such as in the event of a strong earthquake.

Emergency generator BACT determinations are much less common than gas turbines. Current BACT guidelines and determinations published in the RBLC and by the following three California Districts were relied on for PSE's proposed emergency generator:

- BAAQMD BACT Guideline for emergency compression ignition internal combustion (IC) engines > 50 hp (http://hank.baaqmd.gov/pmt/bactworkbook/default.htm).
- SJVAQMD BACT Guideline 3.1.1 for emergency diesel IC engines (http://www.valleyair.org/busind/pto/bact/chapter3a.pdf)
- SCAQMD LAER/BACT Determinations for emergency compression ignition (CI) engines (http://www.aqmd.gov/bact/AQMDBactDeterminations.htm).

Current BAAQMD, SCAQMD and SJVAPCD BACT guidelines require new stationary emergency CI engines to meet applicable EPA NSPS or CARB tier standards for NO_x, CO, PM_{10}, and VOC, and to use ULSD to control SO_2 emissions. Federal Tier 2 standards for non-road CI engines currently apply to new stationary emergency standby engines greater than 761 bhp, or 560 brake-kilowatt (bkW) (EPA, *Final New Source Performance Standards for Stationary Compression Ignition Combustion Engines*, 71 FR 39154. July 11, 2006). Note that emergency engines are exempt from the more stringent Tier 4 requirements in the NSPS. CARB is in the process of adopting rule revisions to retain a 0.15 g/bhp-hr limit for PM and align the other pollutant emission standards with federal NSPS requirements for emergency standby CI engines. This change reflects CARB's recent finding that add-on controls (i.e., SCR and diesel particulate filter technology) are not justified for emergency engines due to significant economic and operational constraints (CARB, *Staff Report: Initial Statement of Reasons for Proposed Rule Making – Proposed Amendments for the Airborne Toxic Control Measure for Stationary Compression Ignition Engines*, September, 2010). This CARB finding is consistent with EPA's rationale for exempting emergency CI engines from Tier 4 requirements.

At time of purchase, the Project's proposed emergency standby generator engine will be certified by the manufacturer to meet Tier 2 standards. The Caterpillar engine identified in Section 2.2 and Attachment A-9 has PM emissions that are lower than the CARB's 0.15 g/bhp-hr emission limit (CARB, *Executive Order U-R-001-0380-1 for the 2010 Caterpillar ACPXL 18.1ESW engine family*, August 30, 2010). If a different make/model emergency standby generator is selected during detailed design for the Project, a Tier 2 certified engine will be specified at time of purchase. Furthermore, PSE commits to use ULSD. Therefore, the proposed emergency standby generator meets BACT.

BACT for GHG emissions from the emergency generator is addressed in Attachment H.

5.5 BACT FOR NON-PSD POLLUTANTS

This analysis is provided in support of the NOC application.

5.5.1 NOx

5.5.1.1 Step 1: Available Control Technologies

The following technologies are available for the control of NO_x emissions from gas turbines.

COMBUSTION CONTROLS

Dry Combustion Controls
Combustion modifications that decrease gas turbine NO_x emissions without wet injection (water or steam) include lean combustion, reduced combustor residence time, lean premixed combustion, and two-stage rich/lean combustion. Lean combustion uses excess air (greater than stoichiometric air-to-fuel ratio) in the combustor's primary combustion zone to cool the flame, thereby reducing the rate of thermal NO_x formation. Reduced combustor residence times are achieved by introducing dilution air between the combustor and the turbine sooner than with standard combustors. The combustion gases are at high temperatures for a shorter time, which also has the effect of reducing the rate of thermal NO_x formation.

Wet Combustion Controls
Steam or water injection directly into the turbine combustor is one of the most common NO_x control techniques. These wet injection techniques lower the peak flame temperature in the combustor, reducing the formation of thermal NO_x. The injected water or steam exits the turbine as part of the exhaust. Water and steam injection have been in use on both oil- and gas-fired combustion turbines in all size ranges for many years.

Catalytic Combustors
Catalytic combustors use a catalytic reactor bed mounted within the combustor to burn a very lean fuel-air mixture. This technology has been commercially demonstrated under the trade name Xonon™ in a 1.5-MW natural gas-fired combustion turbine in Santa Clara, California. No turbine vendor, other than Kawasaki, has indicated the commercial availability of catalytic combustion systems at the present time and the largest size is 18 MW. The technology is not commercially available for the engines proposed by PSE; therefore, it is not considered further.

POST-COMBUSTION CONTROLS

Selective Catalytic Reduction (SCR)
SCR is a post-combustion technique that controls both thermal and fuel-bound NO_x emissions by reducing NO_x with a reagent (generally NH_3 or urea) in the presence of a catalyst to form water and nitrogen. NO_x conversion is sensitive to exhaust gas temperature, and performance can be limited by contaminants in the exhaust gas that may mask the catalyst (sulfur compounds, particulates, heavy metals, and silica). SCR is used in numerous gas turbine installations throughout the United States, almost exclusively in conjunction with other wet or dry NO_x combustion controls. SCR requires the consumption of a reagent (NH_3 or urea) and requires periodic catalyst replacement. Estimated levels of NO_x control are in excess of 90 percent.

Selective Non-Catalytic Reduction (SNCR)
SNCR involves injection of NH_3 or urea with proprietary conditioners into the exhaust gas stream without a catalyst.

Nonselective Catalytic Reduction (NSCR)
NSCR uses a catalyst without injected reagents to reduce NO_x emissions in an exhaust gas stream. NSCR is typically used in automobile exhaust and rich-burn stationary IC engines, and employs a platinum/rhodium catalyst.

SCONOx^{TM}
SCONOx^{TM} is a proprietary catalytic oxidation and adsorption technology that uses a single catalyst for the control of NO_x, CO, and VOC emissions. The catalyst is a monolithic design, made from a ceramic substrate with both a proprietary platinum-based oxidation catalyst and a potassium carbonate adsorption coating. The catalyst simultaneously oxidizes NO to NO_2, CO to CO_2, and VOCs to CO_2 and water, while NO_2 is adsorbed onto the catalyst surface where it is chemically converted to and stored as potassium nitrates and nitrites. The SCONOx^{TM} potassium carbonate layer has a limited adsorption capability and requires regeneration approximately every 12 to 15 minutes in normal service. Each regeneration cycle requires approximately 3 to 5 minutes. At any point in time, approximately 20 percent of the compartments in a SCONOx^{TM} system would be in regeneration mode, and the remaining 80 percent of the compartments would be in oxidation/absorption mode.

5.5.1.2 Step 2: Eliminate Technically Infeasible Options

Three of the technologies identified above – SNCR, NSCR and SCONOx^{TM} – have been eliminated as technically infeasible. SNCR technology requires gas temperatures in the range of 1,200°F to 2,000°F and is most commonly used in boilers. Some method of exhaust gas reheat, such as additional fuel combustion, would be required to achieve exhaust temperatures compatible with SNCR operations, and this requirement makes SNCR technologically infeasible for the Project.

NSCR is effective only in a stoichiometric or fuel-rich environment where the combustion gas is nearly depleted of oxygen, and this condition does not occur in turbine exhaust where the oxygen concentrations are typically between 14 and 16 percent. For this reason, NSCR is not technologically feasible for the Project.

SCONOx^{TM} has also been eliminated as technically infeasible because it has not been demonstrated in practice for a simple cycle gas turbine. Although it was originally tested at a small combined-cycle power plant in Southern California, SCONOx^{TM} has never been demonstrated on a full-scale utility generator. More relevant to this Project, it has not been tested or demonstrated for simple cycle gas turbine applications. The exhaust temperature characteristics of the Project's gas turbines would not be compatible with SCONOx^{TM} and could lead to damage of the SCONOx^{TM} catalyst. Additional engineering would be required to temperate the exhaust; related research and development has not been conducted by this technology's supplier to PSE's knowledge. Furthermore, there are serious questions about the successful application of the SCONOx^{TM} technology for utility-scale power plants in general, as well as the levels of emission control that can be consistently achieved. CEC staff has determined in recent California citing cases that SCONOx^{TM} is not a preferable alternative, stating: "*Applicant also reviewed alternative technologies for air pollution control and* *combustion modification, including:" ... "SCONOx^{TM}. None of the alternative pollution control technologies is more effective than that proposed for the project due to their lack of commercial viability in a scaled-up project and/or their technological infeasibility for a peaking unit." ... "Therefore, the evidence shows that none of the alternative fuels or technologies is a feasible option*" (*San Francisco Electric Reliability Project, Final Commission Decision*, CEC-800-2006-007-CMF. October 2006, p. 27). Therefore, this technology is not considered feasible for the Project.

5.5.1.3 Steps 3-5: Rank Remaining Control Options, Evaluating and Selecting BACT

PSE proposes to use the most effective combination of control options that are available and feasible. PSE proposes to use dry low-NO_x combustion for all three frame turbine options when burning natural gas. All three frame turbine options use water injection when burning fuel oil. With dry combustors, the GE 7FA.04 and GE 7FA.05 frame turbines are capable of achieving 9 ppmvd NO_x @ 15% O_2 at the turbine outlet when burning natural gas. The Siemens SGT6-5000F4 is capable of achieving 28 ppmvd NO_x @ 15% O_2 with dry combustion while burning natural gas.

All three frame turbine options require water injection for NO_x control to achieve 42 ppmvd NO_x @ 15% O_2 emissions at the turbine outlet when burning fuel oil. The aeroderivative GE LMS100 engine requires water injection to achieve turbine outlet NO_x concentrations of 25 ppmvd NO_x @ 15% O_2 on natural gas and 42 ppmvd NO_x @ 15% O_2 on fuel oil.

SCR will be used on this Project in conjunction with the dry or wet NO_x combustion controls on the proposed gas turbine options to achieve BACT. The SCR system for all four turbine options will be designed to achieve 2.5 ppmvd NO_x @ 15% O_2 at the stack outlet while burning natural gas and 5.0 ppmvd NO_x @ 15% O_2 while burning fuel oil. As needed, tempering air may be injected to cool turbine exhaust gases to the temperature range required by modern SCR catalysts; the requirement for tempering air depends on which gas turbine engine model is selected by PSE and can vary with operating conditions.

PSE proposes to control NO_x emissions from the stack to 2.5 ppmvd @ 15% O_2 while burning natural gas, which is consistent with the BACT determinations summarized in Tables 5-1, 5-2 and 5-3 for projects that burn only natural gas. PSE will use natural gas whenever it is reasonably available. During infrequent periods of backup fuel oil use, the SCR system will control NO_x emissions to 5.0 ppmvd @ 15% O_2, which is also consistent with prior BACT determinations. Specific controlled emission rates for each turbine option and operating scenario are provided in Attachment A.

5.5.2 CO

PSD BACT is addressed above in Section 5.3.2 for the Siemens engine option. The Project's LMS100, GE Frame 7FA.04 & 05 turbine options are addressed below.

5.5.2.1 Step 1: Available Control Technologies

Available control technology options for CO emissions from gas turbine engines are the use of 1) low CO emitting fuels, 2) good combustion practices and 3) add-on technology such as oxidation catalyst to oxidize CO in the gas turbine exhaust stream. CO emissions from gas turbines typically vary with operating conditions including turbine load and ambient temperature, and with fuel.

5.3.2.2 Step 2: Eliminate Technically Infeasible Options

Although the exclusive use of natural gas would reduce CO emissions, this is not a feasible option for the Project. As explained above, PSE has an obligation to serve its customers and must have the ability to use ultra-low sulfur diesel when natural gas is not reasonably available. PSE has, however, committed to using natural gas as fuel whenever it is reasonably available.

5.3.2.3 Steps 3-5: Rank Remaining Control Options, Evaluate and Select BACT

PSE proposes to use the most effective or top control option, an oxidation catalyst. An oxidation catalyst will reduce CO emissions to 4 ppmvd @ 15% O_2 or less when burning natural gas if the 7FA.05 or 7FA.04 turbine options are selected, or 5.1 ppmvd @ 15% O_2 or less if the LMS100 turbine option is selected. This is consistent with recent BACT determinations for natural gas-fired turbines.

During infrequent use of backup fuel oil, the 7FA.05, 7FA.04, and LMS100 turbine options will be capable of achieving 8.0, 7.7, and 3.9 ppmvd CO at 15% O_2 or less, respectively. Specific controlled emission rates are provided in Attachment A and proposed turbine-specific emission limits are listed in Table 5-6.

These CO emission concentrations are within the lower range of recent BACT determinations documented for fuel oil in the RBLC in Tables 5-1 and 5-2. Recent BACT determinations summarized in Tables 5-1, 5-2 and 5-3 range from as low as 2 ppmvd CO @ 15% O_2 to as high as 63 ppmvd CO @ 15% O_2 when operated on natural gas, and as low as 5 ppmvd CO @ 15% O2 to as high as 30 ppmvd CO @ 15% O_2 when operated on fuel oil. For frame-sized turbines comparable to the Project's 7FA.05 and 7FA.04 turbine options, however, BACT determinations have generally resulted in a limit of 6 ppmvd CO @ 15% O_2 when fired with natural gas. There are two exceptions. The Marsh Landing and Mariposa Energy projects have been permitted with a 2 ppmvd @ 15% O_2 limit, but those limits have not been achieved in practice. In fact, the District that permitted the Mariposa Energy facility stated that 2 ppm "is more stringent than what has been achieved in practice at other similar simple cycle facilities and is the most stringent limit that is technologically feasible and cost effective" (BAAQMD, *Final Determination of Compliance – Mariposa Energy Project*, November 2010). Other determinations for smaller engines (e.g., LM6000) are not considered to be representative of PSE's proposed larger frame-sized and LM100 turbine options because they have different emission characteristics.

5.5.3 VOC

5.5.3.1 Step 1: Available Control Technologies

Available control technology options for VOC emissions from gas turbines generally include 1) good combustion practices and 2) add-on technology such as an oxidation catalyst in the gas turbine exhaust stream.

Recent BACT determinations are summarized in Tables 5-1, 5-2 and 5-3. They generally indicate a 2 ppmvd @ 15% O_2 BACT limit for both the frame turbines and the GE LMS 100 when fired on natural gas. The 1.3 ppmvd @15% O_2 BACT determination for the Pastoria

Energy Facility's GE 7FA.03 peaker unit is a outlier for this type of turbine. The Mariposa Project does not use turbines similar to those proposed by PSE, and the 1 ppmvd @15% O_2 BACT determination has not been fully approved by the CEC to date or demonstrated in practice.

5.5.3.2 Step 2: Eliminate Technically Infeasible Options

No available control technologies were eliminated as infeasible.

5.5.3.3 Steps 3-5: Rank Remaining Control Options, Evaluate and Select BACT

BACT for VOC emissions from the Project will be achieved by using an oxidation catalyst as a post-combustion control technology to reduce VOC emissions to a maximum of approximately 2 ppmvd @ 15% O_2 when burning natural gas. This is top control option and consistent with recent BACT determinations for natural gas-fired turbines. The Project’s 7FA.05, 7FA.04, 5000F4 and LMS100 turbine options are capable of achieving 1.4, 1.3, 1.0, and 2.6 ppmvd @ 15% O_2 or less, respectively. As stated above, PSE commits to burn natural gas whenever it is reasonably available.

During infrequent use of backup fuel oil, the Project’s three proposed frame turbine options will be capable of achieving 3.1 ppmvd VOC at 15% O_2 or less, however the GE LMS100 option is estimated to reach levels as high as 5.6 ppmvd VOC at 15% O_2 on fuel oil.

Specific controlled emission rates for each turbine option and operating scenario are provided in Attachment A, and proposed emission limits are listed in Table 5-6**.**

5.5.4 SO_2

5.5.4.1 Step 1: Available Control Technologies

Available control technology options for SO_2 emissions from gas turbines generally include good combustion practices, and the use of fuels that have low ash and sulfur content. Fuel sulfur, when combusted, forms various SO_x, including SO_2, that can react with other exhaust constituents (e.g., NH_3 from an SCR) to form condensable PM.

SO_2 BACT determinations for projects listed in Tables 5-1 and 5-2 are based fundamentally on the use of good combustion practices and pipeline natural gas for gas turbine power projects.

SO_2 emissions vary with operating conditions and the amount and type of fuel combusted. Oxidation catalyst systems described above for CO and VOC control, will reduce SO_2 emissions slightly by oxidation. This reaction is considered in the emission estimates provided in this application (see Attachment A).

5.5.4.2 Step 2: Eliminate Technically Infeasible Options

As explained above, the exclusive use of natural gas as fuel was eliminated as a technically infeasible option. In order to maintain a safe and reliable local/regional power grid, PSE must continue to operate the proposed generating unit(s) whenever their power is needed. PSE proposes to use natural gas whenever it is reasonably available. Ultra-low sulfur diesel will be used during what are expected to be very infrequent shortages in natural gas pipeline capacity.

5.5.4.3 Steps 3-5: Rank Remaining Control Options, Evaluate and Select BACT

PSE proposes to use good combustion practices and to use natural gas as the fuel whenever it is reasonably available. The maximum expected SO_2 stack emission rate is 0.73 ppmvd @ 15% O_2, which is far below the 1,000 ppmvd state emission standard.

5.6 TOXIC AIR POLLUTANTS

In addition to BACT for PSD pollutants, Washington rules require that tBACT also be applied to TAP emissions. The following tBACT analysis is provided for the NOC application, but is not a part of the PSD application. With the exception of NO_x and NH_3, nearly all of the toxic emissions from the Project fall into the category of PM or VOC. Thus, the same controls that are discussed above for NO_x, PM_{10} (and $PM_{2.5}$), VOC and NH_3 are considered to be BACT for toxic emissions as well. Additional details and summaries for each of these pollutant groups are provided below.

5.6.1 Nitrogen Dioxide

The control technology proposed to achieve BACT levels above will also address tBACT for NO_2.

5.6.2 Particulate TAPs

Baghouses and electrostatic precipitator (ESP) control technologies that are typically used to control particulate matter emissions from other source types such as coal-fired boilers, are not technically feasible for IC engines. Particulate emissions from gas turbines and compression IC engines are so small that these controls cannot efficiently remove them. Instead, the use of clean fuels such as natural gas and ULSD are commonly considered BACT for PM_{10} and $PM_{2.5}$, as discussed above, and would be considered as BACT for particulate toxics as well.

5.6.3 Volatile Organic Compound TAPs

VOC toxic emissions can be controlled by oxidation. The proposed oxidation catalyst for the Project should effectively control formaldehyde (the primary air toxic from natural gas combustion) to similar reduction levels as CO emissions. The Project emission estimates assume varying levels of CO control efficiency to achieve targeted BACT exhaust concentrations for the different turbine engine options (approximately 50-95%) and a 30% reduction in VOC due to the oxidation catalyst. Actual VOC destruction efficiency may be closer to 50% or higher levels that are commonly cited in the literature. Efficiencies for the Project's oxidation catalyst will not be known until a catalyst vendor is selected.

5.6.4 Ammonia

Ammonia is not a federal HAP, but it is a TAP in Washington. Ammonia is used as a reactant in the proposed SCR system to control NO_x emissions. Some unreacted NH_3 slips through the SCR catalyst bed. Ammonia (NH_3) slip emissions from SCR systems are commonly limited in air permit conditions to 5 or 10 ppmvd @ 15% O_2 in permits that were reviewed for this analysis. The Project's SCR system will be designed not to exceed 10 ppmvd @ 15% O_2. This common NH_3 slip limitation for gas turbines applies to PSE's existing generating stations in the NWCAA region and other Washington regions. It is considered achievable for the Project considering its anticipated operating profile and uncertainties regarding the long-term achievability of a low

NH_3 emission limit and the limited operating experience to date with SCR catalysts on simple cycle gas turbines.

5.7 SUMMARY OF PROPOSED BACT

Tables 5-6 and 5-7 summarize the proposed BACT methods and emission levels for the Project. These control methods and levels are based on the information provided above, which stem primarily from recent and relevant and agreed upon top-down BACT determinations from California that are considered to be conservatively high levels of control for the proposed equipment.

Table 5-6 addresses steady-state turbine operations; i.e., times other than start-ups and shutdowns, and when load is reasonably constant. Table 5-7 presents proposed durations and emission limits for start-ups and shutdowns. Additionally, NO_x emissions during periods of transient load are addressed below.

5.7.1 Transient Load Conditions

Modern simple cycle gas turbine generators are designed to achieve significantly improved rapid responses to load changes on the electrical grid. A more rapid response helps improve system reliability and efficiency. During some periods of rapid load change, known as transient conditions, it may not be possible to maintain compliance with steady-state NO_x BACT emission limits proposed in Table 5-6. Quickly changing turbine loads tend to disrupt the uniformity of temperature profiles, emission concentrations, and exhaust flow rates which, in turn, temporarily affect SCR system performance. In the June 2010 Final Determination of Compliance for the Marsh Landing Generating Station (page 32), the BAAQMD determined that "NO_x emissions performance that can be achieved with combined-cycle turbines would not be achievable for simple cycle turbines." Therefore, BAAQMD decided to impose an alternative 2.5 ppmvd @ 15% O_2 NO_x BACT emission limit averaged over 3 hours (instead of 1 hour) for any transient hour with a load change exceeding 25 MW per minute. To the Applicant's knowledge this it's the only permit to address transient conditions for simple cycle turbines to date. Permit Condition 17 for the Marsh Landing facility specifies that the 3 clock-hour-hour averaging period for this alternative limit is to be calculated using the clock hour immediately prior to, and continuing through the clock hour immediately following the transient hour (page 91). PSE requests a similar alternative NO_x limit for the Project to address transient conditions.

Table 5-6
Summary of Proposed Steady-State BACT Limits for the Project

Pollutant (Avg. Period)	Control Technology	Emission Limit
Simple Cycle Turbines		
NO_x (1-hour during steady-state, 3-hr during transient load conditions) *Not PSD BACT*	Low NO_x combustors, and SCR	2.5 ppmvd at 15% O_2 (natural gas), or 5.0 ppmvd at 15% O_2 (ULSD)
CO (3-hour) PSD BACT only for the Siemens SGT6-5000F4 turbine option	Catalytic oxidation (or equivalent emissions)	7FA.05: 4.0ppmvd (gas), or 8.0 ppmvd (ULSD) at 15% O_2 7FA.04: 4.0ppmvd (gas), or 7.7 ppmvd (ULSD) at 15% O_2 5000F4: 4.0 ppmvd (gas), or 12.0 ppmvd (ULSD) at 15% O_2 LMS100: 5.1 ppmvd (gas), or 3.9 ppmvd (ULSD) at 15% O_2
VOC (as CH_4) (3-hour) *Not PSD BACT*	Catalytic oxidation (or equivalent emissions)	7FA.05: 1.4ppmvd (gas), or 3.1 ppmvd (ULSD) at 15% O_2 7FA.04: 1.3 ppmvd (gas), or 2.8 ppmvd (ULSD) at 15% O_2 5000F4: 1.0 ppmvd (gas), or 3.0 ppmvd (ULSD) at 15% O_2 LMS100: 2.6ppmvd (gas), or 5.6 ppmvd (ULSD) at 15% O_2
SO_2 (3-hour) *Not PSD BACT*	Pipeline natural gas, or ULSD when natural gas is not reasonably available	7FA.05: 8.22 lb/hr (nat. gas), 1.26 lb/hr (ULSD) 7FA.04: 7.01 lb/hr (nat. gas), 1.12 lb/hr (ULSD) 5000F4: 7.39 lb/hr (nat. gas), 1.09 lb/hr (ULSD) LMS100: 3.26 lb/hr (nat. gas), 0.50 (ULSD) – (x 2)[1]
H_2SO_4 mist (24-hour)	Pipeline natural gas, or ULSD when natural gas is not reasonably available	7FA.05: 22.01 lb/hr (nat. gas), 3.36 lb/hr (ULSD) 7FA.04: 25.23 lb/hr (nat. gas), 3.02 lb/hr (ULSD) 5000F4: 22.98 lb/hr (nat. gas), 3.38 lb/hr (ULSD) LMS100: 8.73 lb/hr (nat. gas), 1.28 (ULSD) – (x 2)
PM_{10} and $PM_{2.5}$ (3-hour)	Pipeline natural gas, or ULSD when natural gas is not reasonably available	7FA.05: 47.70 lb/hr (nat. gas), 38.50 lb/hr (ULSD) 7FA.04: 46.40 lb/hr (nat. gas), 38.40 lb/hr (ULSD) 5000F4: 40.00 lb/hr (nat. gas), 34.60 lb/hr (ULSD) LMS100: 17.80 lb/hr (nat. gas), 26.70 (ULSD) – (x 2)
Ammonia slip (24-hour) *Not PSD BACT*	Operational limitation	10.0 ppmvd @ 15% O_2
Greenhouse Gases (Annual)	High-efficiency simple cycle gas turbine technology	7FA.05: 1,299 lb CO_2e /MW-hr 7FA.04: 1,310 lb CO_2e /MW-hr 5000F4: 1,278 lb CO_2e /MW-hr LMS100: 1,138 lb CO_2e/MW-hr[2]
Emergency Generator		
All	EPA Tier 2 Engine	See NSPS Tier 2 rules

Notes:
[1] lb/hr emission estimates for the LMS100 option are presented for a single turbine. Multiply by 2 for the Project's proposed emission limits.
[2] lb CO_2e /MW-hr values in this table are based on detailed worst-case emission calculations in Attachment A-3 using PSE's estimated annual operating scenario for each turbine option. Two LMS100 turbines are included.

Table 5-7
Summary of Start-Up and Shutdown BACT Limits for the Project

Pollutant	Duration (minutes) Start-up	Duration (minutes) Shutdown	Emissions per Event (lb) Start-up Natural Gas	Emissions per Event (lb) Start-up ULSD	Emissions per Event (lb) Shutdown Natural Gas	Emissions per Event (lb) Shutdown ULSD
GE 7FA.05						
NO_x	30	19 (gas) 17 (oil)	31.5	146	16.0	79.0
CO			210	332	189	196
VOC			5.9	8.6	4.3	6.0
PM, PM_{10}, $PM_{2.5}$			9.2	17.0	5.8	9.6
SO_2			10.4	1.1	4.6	0.4
GE 7FA.04						
NO_x	30	14	43.1	168	31.0	107
CO			106	140	90.0	95.0
VOC			6.5	5.0	4.8	2.0
PM, PM_{10}, $PM_{2.5}$			5.8	17.4	4.4	8.4
SO_2			10.1	1.1	4.2	0.4
Siemens SGT6-5000F4						
NO_x	35 (gas) 38 (oil)	17 (gas) 19 (oil)	92.4	146	45.0	90.0
CO			1347	1462	443	709
VOC			154	162	50.0	76.0
PM, PM_{10}, $PM_{2.5}$			4.8	15.6	2.4	10.0
SO_2			11.0	1.0	5.4	0.7
GE LMS100						
NO_x	30	8	34.5	59.9	3.4	5.7
CO			49.0	39.6	1.8	1.7
VOC			1.0	3.7	0.03	0.06
PM, PM_{10}, $PM_{2.5}$			3.3	14.3	1.0	4.7
SO_2			6.5	0.6	0.7	0.05

Source: Attachment A-9.

6.1 INTRODUCTION

Modeling for a PSD analysis must adequately simulate the concentration increases of emitted pollutants, which are used to demonstrate compliance with ambient air quality standards. The facility emissions include criteria pollutants that will be assumed to be inert for the purpose of NAAQS analyses. In keeping with EPA and Ecology policy, no photochemical modeling for ozone was conducted since VOC emissions do not exceed the SER.

EPA's Guideline on Air Quality Models (Appendix W to 40 CFR 51) recommends the use of the AERMOD dispersion model for PSD analyses of criteria pollutants for distances out to 50 km. AERMOD is the preferred dispersion model for sources located in all types of terrain (simple and/or complex), and for sources subject to aerodynamic building downwash. The modeling analysis was done using the current version of the AERMOD model (Version 09292).

6.2 AERMOD MODEL INPUT

The modeling approach was documented in PSE's *Modeling Protocol for Puget Sound Energy Fredonia Generating Station Proposed Development Project*, submitted September 24, 2010, along with additional amendments and correspondence with Ecology and the FLM. These detailed documents are provided in Attachment B of this application. A summary description of the methodology is given below.

6.2.1 Emissions

The emissions estimates, and scenario development, are discussed in detail in Section 3 above, and additional detailed information, along with reference material are provided in Attachment A. The criteria pollutant analysis used a two stage approach to develop worst-case scenarios for each turbine option. Table 3-3 provides the source parameters, and predicted impacts for each operating condition (by load and ambient temperature for each turbine option). Based on these load check results, the refined worst-case scenario modeling analyses were determined for each option. The source parameters and emission rates for these cases are provided in Table 3-4. These worst-case scenario parameters are used for all the criteria pollutant analyses.

The emergency generator is included in the refined modeling analyses. Stack parameters and emissions from the emergency generator are shown in Table 3-5. Only the location of the generator changes between the four turbine options; the worst-case usage, stack parameters, and emissions are modeled the same way for each of the options.

6.2.2 Building Downwash

For each turbine option, the facility layout, including structure elevations, was used to enter building locations and dimensions into the Building Profile Input Program for the PRIME algorithm (BPIP-PRIME). The conceptual site layouts for the four turbine options are shown in Figures 2-2 through 2-4. The structure coordinates and heights are shown in the modeling files (in Attachments C-3 and C-4), and the data for these are provided in Attachment C-2.

6.2.3 Elevation Data and Receptor Grid

Terrain elevations and hill height scale values for the sources, buildings, and receptors were prepared using the AERMAP preprocessor with United States Geological Survey (USGS) 7.5-minute digital elevation model (DEM) data. The DEM data for the Fredonia analyses includes the following quadrangles: Alger, Anacortes North, Anacortes South, Bow, La Conner, Mt. Vernon, Sedro-Woolley North, and Sedro-Woolley South.

Receptors are located on a Cartesian grid system as follows: 25-meter grid from fenceline out to a distance 100m; 50-meter grid out to 250m; 100-meter grid out to 500m; 250-meter grid out to 1000m, and; 500-meter grid out to 2000m. Figure 6-1 shows the receptor grid used for the Class II area analyses. The figure includes the facility layout for the GE 7FA frame turbine options (see Figure 2-2), but the boundary and receptors are the same for all turbine options. Nested 25-meter resolution grids were placed around the initial maximum receptor location (found using the above grid) for each pollutant and averaging period in order to better resolve the maximum impact magnitude and location. Because modeling showed impacts well below SILs, this was only completed for cases where the impacts were within 90 percent of the SIL, which was for the GE LMS100 turbine option, 24-hour $PM_{2.5}$ impacts only. Figure 6-2 shows the refined receptor grids used for this analysis. Receptor elevations are based on USGS 7.5-minute DEM data, as described above.

Receptors for the Class I areas (and Class II MTB) were provided by the FLM (see Attachment B correspondence). The MTB receptors within 50 km of the PSE facility are included in the Class I analysis using AERMOD. Figure 6-3 shows the receptor grid used for the Class I area analyses. As in Figure 6-1, this figure includes the facility layout for the GE 7FA frame turbine options, but the boundary and receptors are the same for all turbine options.

6.2.4 Meteorological Data

Five years (1995 – 1999) of meteorological data from Shell's March Point Refinery was used as input to AERMOD. This meteorological data set is described in the Modeling Protocol. The processed data was provided by Ecology, and has been used in another PSD permit applications for a nearby facility. The data is included in Attachment C-1.

6.3 TURBINE LOAD CHECK ANALYSES

As discussed above in Section 3.2, initial modeling was conducted for each load condition and ambient temperature to determine worst-case scenarios for each turbine option for each applicable pollutant and averaging period. The model input and results of these analyses are shown in Table 3-3, with the worst-case scenario identified in ***bold italics*** (and they are summarized in Table 3-4). These initial analyses include the turbine options by themselves, without an emergency generator, and they do not include startups and/or shutdowns. The full five-year set of meteorological data, along with the full receptor set (Class II areas) were used in the load check analyses.

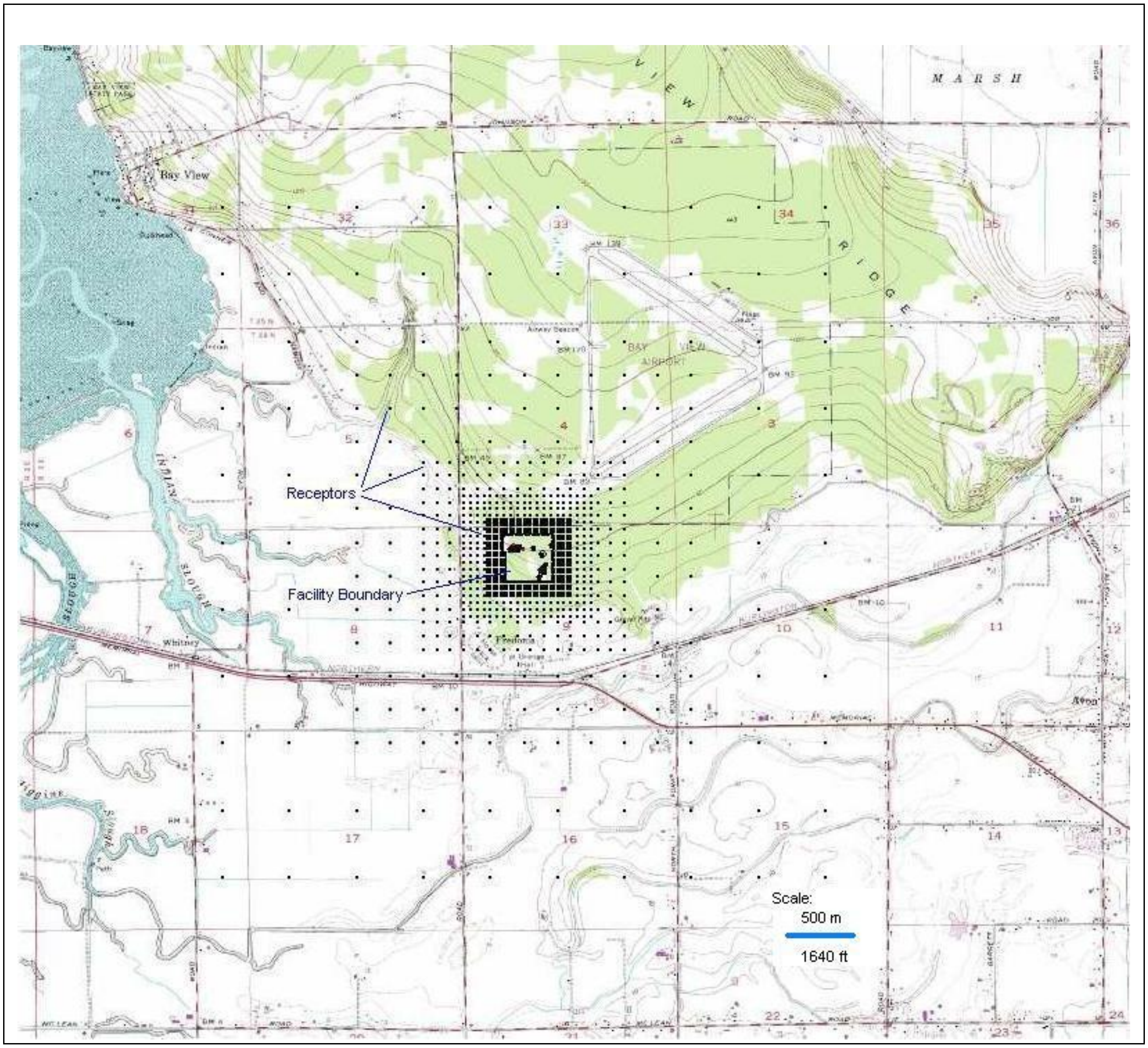


Figure 6-1 Receptor Grid for Class II Area Analyses

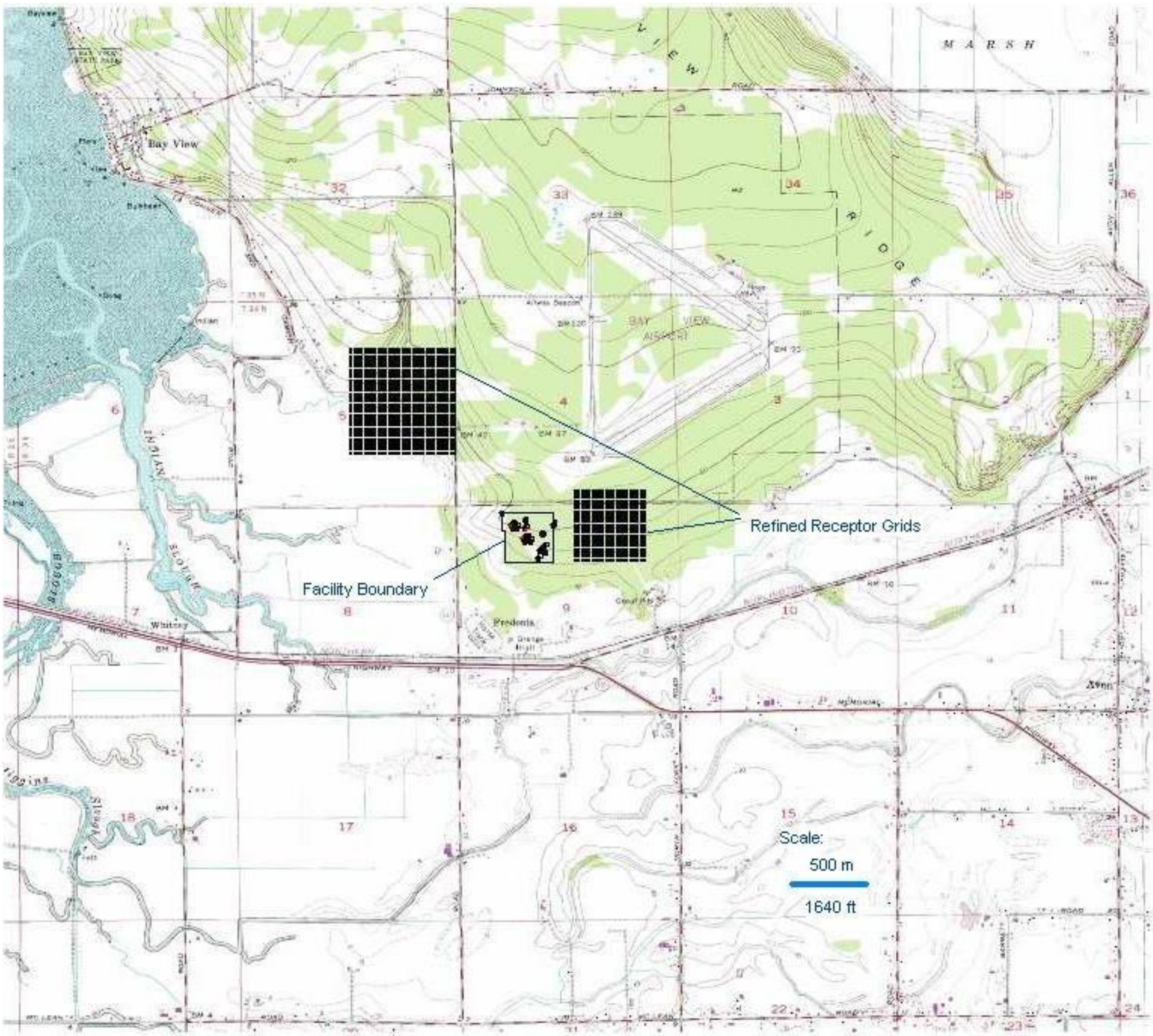


Figure 6-2 Nested Receptor Grid for the GE LMS100 Refined Analysis

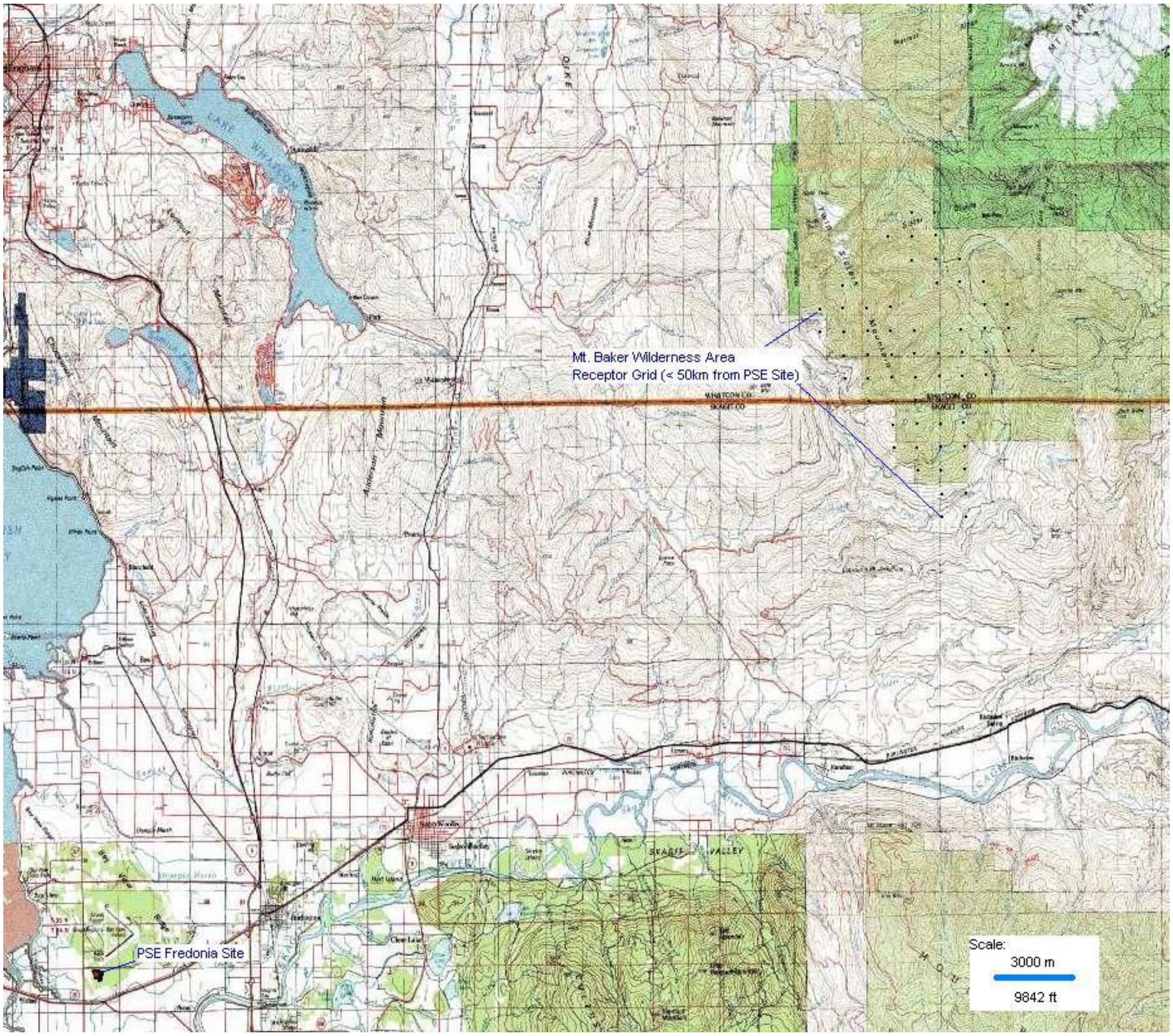


Figure 6-3 Receptor Grid for Class I Area (Mt. Baker Wilderness Area) Analyses

6.4 REFINED MODELING ANALYSES

The refined modeling analyses were performed to estimate offsite criteria pollutant impacts from the proposed project options. The worst-case turbine scenarios are identified in Table 3-4, along with stack parameters and emission rates. The startup and shutdown emissions are included in the total emission rates (where applicable, i.e., when they are higher than normal operating emissions per time period), however, the operating parameters for the load (non-startup or shutdown) are used in the modeling. Table 3-5 shows the same information for the emergency generator, and it is assumed that these worst-case scenarios for each turbine and generator can occur at the same time. Attachment A provides the detailed calculations for emissions and stack information used in the modeling analyses. As with the load check analyses, the refined modeling analyses used the five years of meteorological data and the full receptor set.

In evaluating the potential operational impacts for the proposed Project, AERMOD was used to predict the increases in criteria pollutant concentrations due to the Project emissions only. These impacts were then compared to the SILs to determine whether additional analyses would be required. Table 6-1 shows the impacts for each turbine option. The GE LMS100 turbine option shows the highest impacts, although these are still below the SILs. The maximum 24-hour $PM_{2.5}$ impact for the GE LMS100 using the full receptor grid is 1.11 µg/m^3 (using the 5-year averaging methodology). Because this value is close to the SIL, additional fine receptor grids (25-meter spacing) were placed around each year's maximum impact location. The fine spacing refined analysis (see Figure 6-2) showed a slightly increased maximum value (1.149 µg/m^3) as reported in the table. Similarly, the maximum 24-hour PM_{10} impact using the full grid is 1.65 µg/m^3, and it is 1.71 µg/m^3 using the fine-spaced grids (as shown in the table). These maximum impacts occur at locations well within the receptor grids, not on the borders, which would necessitate further grid analyses. Due the low predicted values for all other impacts as compared to their respective SILs, no additional modeling was performed on the finer grid spacing. Based on these results, no further analysis is required for criteria pollutants in Class II areas.

In addition, modeling was also conducted using the same worst-case scenarios for the receptors at the MTB. Even though this is a Class II area, these predicted impacts are compared to the Class I SILs in Table 6-2, below. Due to the limits of AERMOD, this analysis only looks at the receptors that are within 50km of the Project. However, because these impacts are all well below their respective SILs, no further Class I analysis has been completed. The nearest distance from the Project to the MTB is 41km; the nearest Class I area is 69km (North Cascades National Park). Therefore, it is expected that all Class I areas within 100km of the Project have impacts well below the SILs, and no further analysis is required.

Attachment C provides the modeling files (input and output) for the AERMOD analyses demonstrating compliance with the NAAQS.

Table 6-1
Criteria Pollutant Impacts for the Potential Turbine Options at Class II Areas

Pollutant / Averaging Period	Maximum Predicted Impacts (µg/m^3)				Class II Significant Impact Level (µg/m^3)
	GE 7FA.05	GE 7FA.04	Siemens SGT6-5000F4	GE LMS100 (2 Units)	
CO – 1 Hour	--	--	110	--	2,000
CO – 8 Hour	--	--	23	--	500
PM_{10} – Annual	0.007	0.007	0.004	0.02	1.0
PM_{10} – 24 Hour	1.04	1.04	0.48	1.71	5.0
$PM_{2.5}$ – Annual	0.007	0.007	0.004	0.02	0.3
$PM_{2.5}$ –24-Hour[1]	1.04	1.04	0.48	1.149	1.2

[1] EPA provided guidance for conducting impact analyses for compliance demonstration of the 24-hour $PM_{2.5}$ SIL (EPA, *Modeling Procedures for Demonstrating Compliance with $PM_{2.5}$ NAAQS*, Memorandum from Stephen D. Page (Office of Air Quality Planning and Standards), March 23, 2010). This guidance gives the option of using the average of the first highest 24-hour averages, based on 5 years of National Weather Service data. Values provided here for the Frame turbine options include the maximum impact only, without utilizing the averaging technique; no further receptor-by-receptor analysis was completed because these conservative values are already below the SIL. The averaging technique was used for the LMS100 turbine option.

Table 6-2
Criteria Pollutant Impacts for the Potential Turbine Options at Class I Areas

Pollutant / Averaging Period	Maximum Predicted Impacts (µg/m^3)				Class I Significant Impact Level (µg/m^3)
	GE 7FA.05	GE 7FA.04	Siemens SGT6-5000F4	GE LMS100 (2 Units)	
PM_{10} – Annual	0.001	0.001	0.001	0.001	0.08
PM_{10} – 24 Hour	0.041	0.041	0.037	0.055	0.27
$PM_{2.5}$ – Annual	0.001	0.001	0.001	0.001	0.06
$PM_{2.5}$ –24-Hour	0.041	0.041	0.037	0.055	0.07

7.1 INTRODUCTION

As described in Section 4.4, AQRV and visibility analyses are required for the following areas: Mt. Baker Wilderness Area (MTB, a Class II protected area located approximately 42 km from the Project site), North Cascades National Park (NCNP), Olympic National Park (ONP), and Glacier Peak Wilderness (GPW) (the Class I areas within 100km of the Project), and Alpine Lakes Wilderness (ALW, a Class I area located just over 100 km from the Project site).

The procedures for demonstrating acceptable impacts from the PSE Fredonia project were detailed in the Modeling Protocol and subsequent correspondence with the FLM (see Attachment B). As discussed in the Protocol, the objective of the AQRV analysis is to demonstrate that air emissions from the proposed Project would not cause or contribute to a significant impact on visibility, regional haze or total nitrogen (N) or total sulfur (S) deposition in any of the specifically modeled Class I areas.

7.2 AQRV SCREENING ANALYSIS

Subsequent PSE's submittal of the Modeling Protocol in September 2010, the National Park Service (NPS), United States Fish and Wildlife Service (FWS) and the USFS released the new FLAG 2010 guidance *Federal Land Mangers' Air Quality Relative Values Work Group (FLAG) Phase 1 Report –Revised (2010)* (Natural Resources Report NPS/NRPC/NRR – 2010/232, October, 2010; 75 FR 207, October 27, 2010). This final version of updates, initially issued in 2008, includes a threshold ratio of emissions to distance (Q/d), below which AQRV review is not required. The criteria threshold was adopted from a similar screening method from EPA's *Regional Haze Regulations and Guidelines for Best Available Retrofit Technology (BART) Determinations* (70 FR 128, July 6, 2005), which is used to screen out of AQRV review those sources with relatively small emissions located far from a Class I area. Specifically, the FLAG 2010 "10D" Rule is:

If Q (tpy)/d (km) is less than 10, no AQRV analysis is required, where:

- Q is the emission increase of SO_2, NO_x, PM_{10}, and H_2SO_4 mist combined in tons per year (tpy); and,
- d is the nearest distance to a Class I Area in kilometers (km).

If Q/d is less than 10 for a Class I Area, then presumptively, there is no adverse impact and a project "screens out" of a Class I AQRV analysis. If Q/d results in a value above 10, a Class I analysis is required.

Based on the FLAG 2010 guidance, estimates were made for the Project's maximum 24-hour emission rates, and then prorated to an annual emission rate assuming full-time (8760 hours) operation. These estimates were made for each turbine option. Table 7-1 provides the estimates of both the specific pollutant emission rates, and the total emissions, Q, for each turbine technology option (inclusive of 24 hours of emergency engine use). These values are then divided by the distance to the nearest Class I area (NCNP at 69 km from the PSE project site). Using these conservative estimates for emissions, all of the Project's options have a Q/d value below 10 (for each Class I area), therefore no further AQRV analyses is required. However, AQRV analyses were conducted for the protected Mount Baker Wilderness Area (Class II area); these analyses are shown below. Attachments C-4 and D-3 provide the detailed calculations used in Table 7-1; emissions are based on data provided in Attachment A.

Table 7-1
AQRV Q/d Screening Analysis

	Turbine Option			
	GE 7FA.05	**GE 7FA.04**	**Siemens SGT6-5000F4**	**GE LMS100 (2 Units)**
Maximum Emissions (lb/hr) on a 24-hour Basis[1] :				
NO_x	52	30	52	39
PM_{10}	48	46	40	54
SO_2	10	9	9	9
H_2SO_4	22	19	23	17
Sum of Emissions Prorated to Full-Time Annual Basis (tpy)[2]:				
Q	578	458	543	517
AQRV Screening[3]:				
Q/d	**8.38**	**6.64**	**7.87**	**7.49**

[1] Emission rates include emergency generator operation.
[2] Annual emissions (Q) assume 8760 hours at maximum 24-hour lb/hr emission rate.
[3] Distance to nearest Class I Area is 69 km (NCNP).

7.3 CALPUFF ANALYSIS FOR MT. BAKER WILDERNESS AREA

7.3.1 Model Selection and Setup

Based on the screening analysis above, only the Class II MTB requires further AQRV analysis to assess air quality impacts within the Wilderness Area. For receptors within 50km of the Project, the criteria pollutant analysis showed impacts were below significance (see Section 6.4 above). The additional visibility impact analysis within 50 km is typically conducted using VISCREEN or PLUVUE models as the analysis methodology shown in the *Workbook for Plume Visual Impact Screening (Revised)* (EPA-454/R-92-023, October 1992). However, there is a considerable obstacle to plume transport directly from PSE Fredonia to the Class II MTB Wilderness area imposed by the Lyman Hills. Both Rick Graw (USFS)and Clint Bowman (Ecology) agree that there are no adequate tools to address plume blight for this particular scenario, thus neither VISCREEN nor PLUVUE analyses were conducted. Instead USFS and Ecology recommended using the CALPUFF model to address visibility impacts for the entire MTB wilderness area (both within and beyond 50 km). Using CALPUFF for the MTB receptors within 50km also provides continuity for the regular analysis for receptors beyond 50km using this same model (see below).

The CALPUFF air dispersion model is the preferred model for long-range transport, as recommended by the FLAG guidance and the Interagency Working Group on Air Quality Modeling (IWAQM) *Phase 2 Summary Report and Recommendations for Modeling Long Range Transport Impacts* (December 1998). To estimate air quality impacts for the entire MTB area, the CALPUFF model (Version 5.8, Level 070623) was used in conjunction with the CALMET diagnostic meteorological model (described below in Section 7.3.3). CALPUFF is a puff-type model that can incorporate three-dimensionally varying wind fields, wet and dry deposition, and atmospheric gas and particle-phase chemistry. The development of model inputs and options for CALMET/CALPUFF processor follow guidance provided in following references:

- FLAG Phase I Report –Revised (2010);
- IWAQM Phase 2 Summary Report and Recommendations for Modeling Long Range Transport Impacts (December 1998); and
- EPA's *Clarification on EPA-FLM Recommended Settings for CALMET* (August 31, 2009);

In addition to these reference materials, AQRV modeling analysis direction was also provided by Rick Graw of the USFS (see Attachment B).

The CALPUFF options were essentially selected to follow EPA's recommended settings for regulatory modeling. The regulatory default switch (MREG = 1) was set to force all model inputs to the EPA-approved regulatory settings. Size parameters for dry deposition of nitrate (NO_3), sulfate (SO_4), and PM_{10} particles were based on default CALPUFF model options. Chemical parameters for gaseous dry deposition and wet scavenging coefficients were based on default values presented in the CALPUFF User's Guide. Calculation of total nitrogen (N) deposition includes the contribution of nitrogen resulting from the ammonium ion of the ammonium sulfate compound. For the CALPUFF runs that incorporate deposition and chemical transformation rates (i.e. deposition and visibility), the full chemistry option of CALPUFF was turned on (MCHEM = 1). The nighttime loss for SO_2, NO_x and HNO_3 were set at 0.2 percent per hour, 2 percent per hour and 2 percent per hour, respectively. CALPUFF was also configured to allow predictions of SO_2, SO_4, NO_x, nitric acid (HNO_3), NO_3 and PM_{10} using the MESOPUFF II chemical transformation module.

Hourly ozone concentration files (OZONE.DAT) were obtained from the USFS (2003 through 2005) to be consistent with the meteorological data. According to Rick Graw (USFS), who provided the data, the fictitious ozone monitoring station was located at the boundary in the MTB Wilderness at the closest point (41 km) to the PSE Fredonia facility. The hourly ozone data for the fictitious ozone monitoring station in MTB was copied from that obtained at Mt. Rainier National Park. Monthly background ozone concentration for missing data in the hourly ozone concentration file was set to 80 parts per billion (ppb). The monthly background ammonia concentration was set to 10 ppb, as recommended by the USFS for this region. The ozone data is included in Attachment D-7.

7.3.2 Modeling Domain and Receptors

The CALMET/CALPUFF modeling domain is shown in Figure 7-1. The 464km-by-336-km domain was initially designed large enough to include all Class I areas of interest with at least an 80 km buffer distance from the most outer-boundary of each Class I area for complex flows that might cause recirculation of plumes originating at the facility. The domain is large enough to assess air quality impact analysis for the MTB.

The CALMET/CALPUFF modeling domain was specified using the Lambert Conformal Conic (LCC) Projection system in order to capture the earth curvature of the large modeling domain more accurately for this Project. The LCC coordinate system was also selected by the University of Washington (UW) for their MM5 simulations of Pacific Northwest Weather. The UW MM5 simulation was used to construct three dimensional meteorological data used in the CALPUFF analysis.

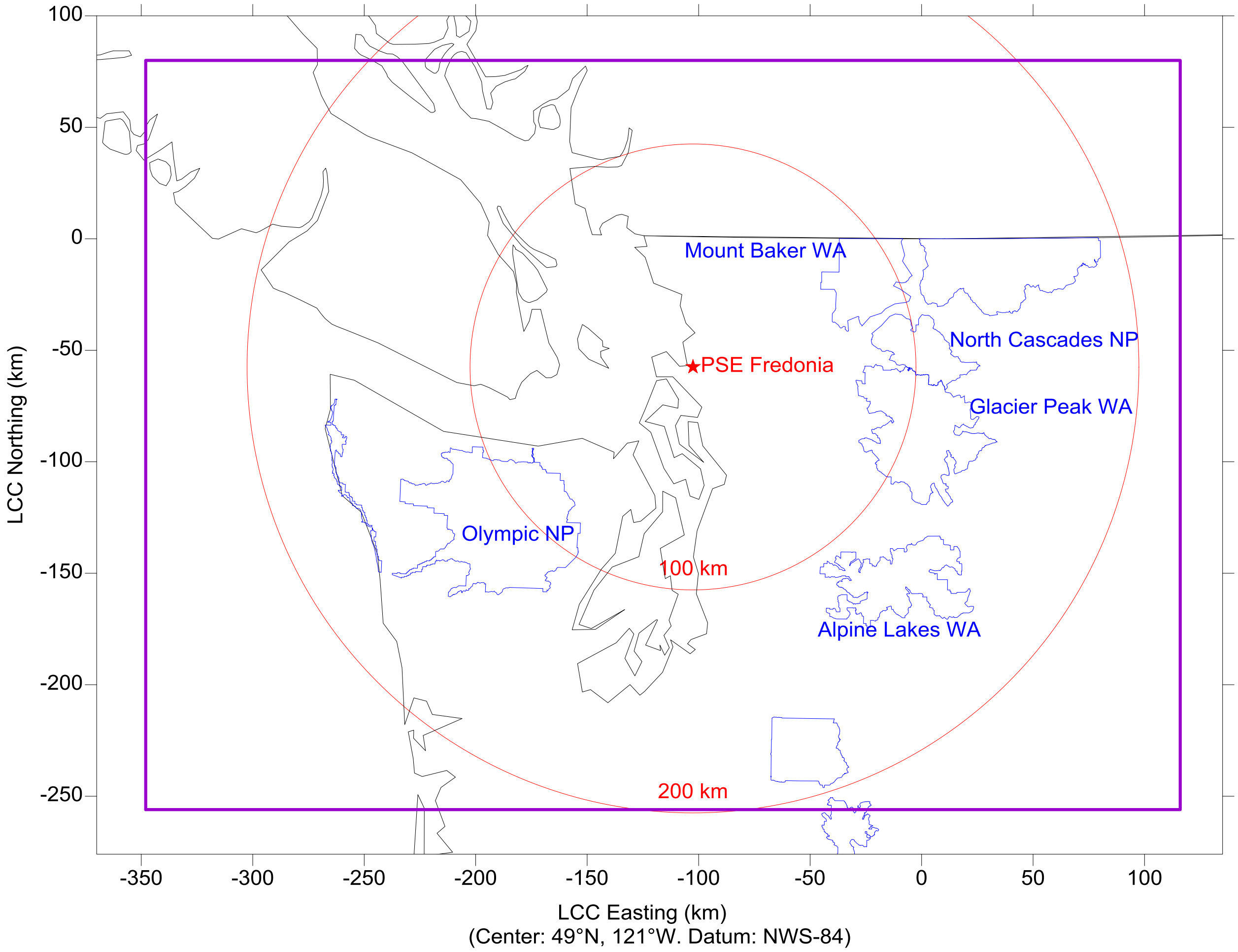


Figure 7-1 Class I Modeling Domain with Selected Class I Areas

Reference: Environ, January 2011.

The false easting and northing at the projection origin were both set to zero. The latitude and longitude of the projection origin were set to 49.0 North and 121.0 West, respectively. Matching parallels of latitude 1 and 2 were defined as 30.0 North and 60.0 North, respectively. The LCC grid projection (origin and matching parallels) were chosen to match the MM5 data. The modeling domain was defined using a grid-cell arrangement that is 117 cells in X (easting) direction and 85 cells in Y (northing) direction. The grid-cells are 4 km wide. Therefore, the southwest corner of the gird cell (1,1) was set to -350 km and -258 km.

Although the MTB is not classified as Class I area, it was included in the analysis per direction of the USFS, and the modeling results were compared with the Class I area thresholds. Figure 7-1 shows the locations of the MTB relative to the proposed site for PSE. The nearest receptor of the MTB is located at41 km and the farthest receptor is located at 86 km from the proposed facility. The entire MTB wilderness area was analyzed via the CALPUFF modeling system.

The receptors of the MTB were obtained from USFS. The receptor elevations for MTB were obtained by processing EPA's AERMAP terrain preprocessor (see description given in Section 6.2.3 above).

7.3.3 CALMET Processing

The AQRV analysis uses three years of hourly 4-km horizontal mesh size MM5 output data from January 2003 to December 2005. The CALMET model was used to prepare the necessary gridded wind fields for use in the CALPUFF model. CALMET can accept as input mesoscale meteorological data (MM5 data), surface, upper air, precipitation, cloud cover, and over-water meteorological data (all in a variety of input formats). These data are merged, and the effects of terrain and land cover types are estimated. This process results in the generation of gridded three-dimensional wind field that accounts for the effects of slope flows, terrain blocking effects, flow channelization, and spatially varying land use types.

ENVIRON was retained by URS on behalf of PSE to perform the CALMET portion of the modeling analysis. The CALMET modeling reference document is included as Attachment D-1.

7.3.4 Source Emissions and Stack Parameters

Required emissions in CALPUFF correspond with the needed analysis and include maximum short-term rates for increment and visibility impacts, as well as maximum annual emissions for species deposition and increment comparison. Because of the various operations involved, and potential occurrence during a specific period, the CALPUFF modeled sources and emissions included potential overlapping operations.

Due to the complexity and extent of the CALPUFF analyses, and also due to the expected low impacts, only one 'worst-case turbine' was evaluated. This worst-case turbine used the maximum emission rate (by pollutant and averaging period) of all four turbine options, inclusive of maximum potential startups and shutdowns (where these values are higher than normal operations). This provides conservatively high emission estimates for the analyses. The maximum potential emission rates for each averaging time period for both natural gas and ULSD are shown in Tables 7-2 and 7-3, respectively. The 24-hour averaged emission rate was used for the visibility impairment impact analysis. The annual averaged emission rate was used for N and S deposition analyses.

For the short-term averaging period (24-hour), the worst-case stack parameters were selected based on AERMOD analyses for each turbine option at the MTB receptors within 50km of the Project site. For these analyses, a unit emission rate was used for each turbine option, and modeling was conducted for each load basis, each ambient temperature, and each fuel type to determine the worst-case stack parameters. The maximum impacts were found to occur with the GE 7FA.05 at 100% load and 7°F ambient temperature when operating on natural gas, and 88°F when operating on distillate. The same procedure was used to evaluate the worst-case turbine on an annual average basis, comparing the four turbine options only for natural gas at 100% load

Table 7-2
Emission Rates for CALPUFF Modeling - Natural Gas Turbine Scenarios

Source	24-hr Average (lb/hr)				Annual Average (lb/hr)			
	NO_x	PM_{10}	$PM_{2.5}$	SO_2	NO_x	PM_{10}	$PM_{2.5}$	SO_2
GE 7FA.05	27.07	47.70	47.70	9.95	5.83	9.62	9.62	1.55
GE 7FA.04	30.18	46.40	46.40	8.92	5.59	9.75	9.75	1.37
Siemens SGT6- 5000F4	45.92	40.00	40.00	9.47	7.39	7.07	7.07	1.43
GE LMS100 (2 Units)	29.85	35.60	35.60	8.63	7.40	9.18	9.18	1.78
Maximum Rates used in Modeling Analysis								
Worst-Case Turbine	45.92	47.70	47.70	9.95	7.40	9.75	9.75	1.78
Emergency Generator	7.653	0.106	0.106	0.010	0.437	0.00607	0.00607	0.00056

Notes:
24-hour average turbine emissions estimates include: 5 startups/shutdowns for NO_x and SO_2; no startup/shutdown for PM (normal operations have higher emissions).
Annual average turbine emissions are based on annual emissions, including startups and shutdowns, assuming all natural gas use.
Emergency generator only operates on distillate fuel, so that is included in the modeling analysis.
Additional emission details are provided in Attachment A and Attachment D-6.

Table 7-3
Emission Rates for CALPUFF Modeling - Distillate Turbine Scenarios

Source	24-hr Average (lb/hr)				Annual Average (lb/hr)			
	NO_x	PM_{10}	$PM_{2.5}$	SO_2	NO_x	PM_{10}	$PM_{2.5}$	SO_2
Maximum Rates - Distillate Use								
GE 7FA.05	52.02	38.41	38.41	1.260	2.051	1.519	1.519	0.051
GE 7FA.04	47.28	38.31	38.31	1.120	1.855	1.515	1.515	0.045
Siemens SGT6- 5000F4	51.24	34.60	34.60	1.090	1.866	1.349	1.349	0.040
GE LMS100 (2 Units)	38.37	53.37	53.37	0.750	1.296	2.109	2.109	0.040
Maximum Rates – Remainder Natural Gas Use								
GE 7FA.05	-	-	-	-	5.086	8.236	8.236	1.497
GE 7FA.04	-	-	-	-	4.946	8.334	8.334	1.330
Siemens SGT6- 5000F4	-	-	-	-	6.630	6.044	6.044	1.395
GE LMS100 (2 Units)	-	-	-	-	6.781	8.135	8.135	1.740
Maximum Rates used in Modeling Analysis								
Worst-Case Turbine (Distillate)	52.02	53.57	53.57	1.260	2.051	2.109	2.109	0.051
Worst-Case Turbine (Remainder Natural Gas)	-	-	-	-	6.781	8.334	8.334	1.740
Emergency Generator	7.653	0.106	0.106	0.010	0.437	0.00607	0.00607	0.00056

Notes:
24-hour average turbine emissions estimates include: 1 startup/shutdown for NO_x; 1 startup/shutdown each for PM for GE LMS100; 1 startup for PM for the GE 7FA's; and no startup/shutdown for SO_2 for any turbine option; or for PM for the Siemens (normal operations have higher emissions).
Annual average turbine emissions are based on annual emissions, including startups and shutdowns, and assume maximum use of distillate (336 hrs) and remainder on natural gas.
Additional emission details are provided in Attachment A and Attachment D-6.

and 51°F (the prevalent operating condition). This evaluation also showed the GE 7FA.05 to be the worst-case turbine. For the modeled annual averaged period, the CALPUFF analysis used the physical parameter of stack height and diameter of the worst-case stack (GE 7FA.05) and the averaged exit temperature and averaged exit gas velocity from all operating scenarios by load for each fuel type, as was done in the AERMOD analysis for annual averaged impacts (see Section 3.2 above). Details regarding the stack parameter determination are provided in Attachment D-4, and modeling files are included in Attachment D-5. The stack parameters used in the CALPUFF modeling for all sources are shown in Table 7-4 for short-term (24-hour) visibility analysis and for annual NS deposition analysis.

The CALPUFF modeling analysis also included the maximum emissions of the emergency generator simultaneous with the worst-case turbine scenario. Testing and maintenance operations are expected to occur 1 hour per week, or 52 hours per year; and operations for the emergency use are conservatively modeled for up to 500 hours per year (total including testing, maintenance, and emergency use). For the 24-hour averaging period, the maximum potential 1-hour emission rate was used (testing and maintenance), to coincide with potential turbine operations which would not be operating under an emergency scenario. For the annual analysis, the annual averaged emission rate was used based upon the conservative 500 hours per year of operation. (Note: these emission rates (and stack parameters) are identical to those used in the AERMOD portion of the analysis.) It was assumed that 100 percent of PM_{10} emission rate is equal to $PM_{2.5}$ emission rate. Therefore, total PM emissions were modeled directly as $PM_{2.5}$ (denoted as PMF in modeling). Tables 7-2 through 7-4 include the CALPUFF emissions and stack parameters for the emergency generator.

The CALPUFF modeling included speciation of emissions following the NPS Particulate Matter Speciation (PMS) method for natural gas combustion turbines and oil fired combustion turbines (http://www2.nature.nps.gov/air/permits/ect/index.cfm). In doing so, the S emissions were speciated to relative sulfur constituents of SO_2 and SO_4 to better account for gas to particulate conversion and visibility effects. Applying the PMS methodology for natural gas combustion turbine, 67 percent of total SO_2 was speciated into SO_2 and 33 percent of total SO_2 was speciated into SO_4. Applying the PMS methodology for oil-fired combustion turbines, 60 percent of total SO_2 was speciated into SO_2 and 40 percent of total SO_2 was speciated into SO_4. The total PM emissions from NG operations were speciated into Elemental Carbon (EC) and Organic Carbon (OC, indicated as "SOA" in the modeling input file). The total PM emissions from distillate operations were speciated into EC, OC (SOA), and Soil. For turbines, the particulate matter emissions were distributed to the size specific particulate matters such as $PM_{0.05}$, $PM_{0.01}$, $PM_{0.15}$, $PM_{0.20}$, $PM_{0.25}$, and $PM_{1.0}$ (indicated as PM0005, PM0010, PM0015, PM0020, PM0025, and PM0100 in the modeling, respectively) according to NPS's PMS method. These size-specific particulate matter were combined into an output group and defined by name as EC in the CALPUFF model. These are smaller than $PM_{2.5}$ (PMF), therefore, CALPUFF modeled the size-specific particulate matter from turbines as EC and CALPOST identified EC with higher extinction efficiency than PMF. Direct emissions of the remaining species, HNO_3 and NO_3, were assumed to be zero. The EC size distribution is shown in Table 7-5. The modeled speciated emissions are shown in Table 7-6. For the emergency generator, the total PM emissions were conservatively modeled as $PM_{2.5}$ (PMF) rather than speciated into both $PM_{2.5}$ (PMF) and PM_{10} (PMC).

Table 7-4
Stack Parameters for CALPUFF Modeling Analyses

Source	Stack Height (ft)	Stack Diameter (ft)	Stack Temperature (°F)	Stack Exit Velocity (fps)
Short-Term Average				
Worst-Case Turbine (Natural Gas)	145	23	800	132
Worst-Case Turbine (Distillate)	145	23	800	132
Annual Average				
Worst-Case Turbine (Natural Gas)	145	23	800	120
Worst-Case Turbine (Distillate)	145	23	800	132
Emergency Generator	50	0.833	994	146

Table 7-5
Size Distribution of EC for Combustion Turbines

Species Name	Size Distribution (%)	Geometric Mass Mean Diameter (microns)	Geometric Std. Deviation (microns)
SO_4	100	0.48	0.50
NO_3	100	0.48	0.50
PM0005	15	0.05	0.00
PM0010	40	0.10	0.00
PM0015	63	0.15	0.00
PM0020	78	0.20	0.00
PM0025	89	0.25	0.00
PM0100	100	1.00	0.00

Source: NPS, http://www2.nature.nps.gov/air/permits/ect/index.cfm.

Table 7-6
Speciated Emission Inventory for CALPUFF Visibility and Deposition Analyses (lb/hr)

Source	SO_2	SO_4	NO_x	HNO_3	NO_3	PMC (PM_{10})	PMF ($PM_{2.5}$)	EC						OC (SOA)	Soil
								PM0005	PM0010	PM0015	PM0020	PM0025	PM0100		
Short-Term Average (Visibility Analysis)															
Worst-Case Turbine **(Natural Gas)**	6.6310	4.9732	45.9153	-	-	-	-	1.7888	2.9813	2.7428	1.7888	1.3118	1.3118	30.8018	-
Worst-Case Turbine (Distillate)	0.7560	0.7560	52.0231	-	-	-	-	1.4866	2.4777	2.2795	1.4866	1.0902	1.0902	32.9947	9.9109
Emergency Generator	0.0098	-	7.6531	-	-	-	0.1063	-	-	-	-	-	-	-	-
Annual Average (Deposition Analysis)															
Worst-Case Turbine **(Natural Gas)**	1.1858	0.8893	7.4027	-	-	-	-	0.3655	0.6091	0.5604	0.3655	0.2680	0.2680	6.4200	-
Worst-Case Turbine (Distillate)	0.0304	0.0304	2.0506	-	-	-	-	0.0585	0.0975	0.0897	0.0585	0.0429	0.0429	1.2982	0.3901
Worst-Case Turbine (Remainder Natural Gas)	1.1602	0.8701	6.7814	-	-	-	-	0.3125	0.5209	0.4792	0.3125	0.2292	0.2292	5.3802	-
Emergency Generator	0.00056	-	0.4368	-	-	-	0.00607	-	-	-	-	-	-	-	-

7.3.5 Class I Area Visibility Reduction Analysis

Based upon FLAG 2010 Guidance, the Q/d value from the proposed project is below 10; therefore, no visibility reduction analysis was conducted for the Class I areas (see Section 7.2 above). However, the analysis was conducted for the protected Class II area, MTB. Emissions and stack parameters for the modeled sources are described in Section 7.3.4 above, including the speciation of emissions. The worst-case short-term (24-hour averaging basis) values are used in the analyses.

CALPOST was used to post-process the estimated 24-hour averaged ammonium nitrate, ammonium sulfate, EC, OC, Soil, $PM_{2.5}$ (PMF) and PM_{10} (PMC) concentrations into an extinction coefficient value for each day at each modeled receptor, using the three years of CALMET meteorological data. To do so, it required the use of extinction efficiency values.

The PM species ($PM_{0.05}$, $PM_{0.01}$, $PM_{0.15}$, $PM_{0.20}$, $PM_{0.25}$, and $PM_{1.0}$) were grouped as EC. Default extinction efficiencies of OC, EC, Soil, $PM_{2.5}$ (PMF), PM_{10} (PMC), ammonium sulfate, and ammonium nitrate were used. $PM_{2.5}$ emission was assigned as PMF, with an extinction coefficient of 1.0. Any remaining PM_{10}, if there is any, which is larger than 2.5 microns, was modeled as PMC, with an extinction coefficient of 0.6.

Based on FLAG 2010, the CALPOST parameter MVISBK was set to eight (MVISBK = 8), sub-mode five (M8_MODE =5), utilizing CALPOST Version 6.292 (per guidance of USFS). Other area-specific input values were taken directly from FLAG 2010, using North Cascades National Park (NCNP) data. Per USFS, NCNP is the nearest representative monitoring site to the MTB. These values include: the annual average natural conditions (background concentrations and Rayleigh scattering); the monthly relative humidity (RH) adjustment factors, f(RH), which are input to the CALPOST RHFAC array and RHFLRG (f_L(RH) values for large hygroscopic particles); the monthly f_S(RH) values for small particles, which are input for RHFSML; and the monthly f_{SS}(RH) values for sea salt, which are input for RHFSEA. Table 7-7 lists the annual average background concentrations and Rayleigh scattering value, and Table 7-8 lists the monthly f(RH) values.

Table 7-7
Annual Average Natural Conditions for Mt. Baker Wilderness Area

Background Concentrations ($\mu g/m^3$)							Rayleigh Scattering (Mm^{-1})
$(NH_4)_2SO_4$	NH_4NO_3	OM	EC	Soil	CM	Sea Salt	
0.11	0.10	0.60	0.02	0.19	1.32	0.02	11

Source: FLAG 2010, Table 6. Values for North Cascades National Park are used to represent Mount Baker Wilderness Area.

Table 7-8
Monthly f(RH) for Mt. Baker Wilderness Area

Parameter	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec
f_L(RH)	3.60	3.32	2.99	2.88	2.74	2.59	2.49	2.63	2.97	3.43	3.77	3.76
f_S(RH)	5.37	4.86	4.24	4.04	3.80	3.51	3.34	3.61	4.23	5.08	5.68	5.66
f_{SS}(RH)	5.03	4.65	4.22	4.08	3.88	3.68	3.53	3.70	4.13	4.78	5.24	5.25

Source: FLAG 2010, Tables 7-9. Values for North Cascades National Park are used to represent Mount Baker Wilderness Area.

The CALPUFF model was run using the three years of MM5 meteorological data (see Section 7.3.3 above). The 98th percentile change in light extinction, which is the 8th highest daily value for each year, was calculated, and these results are compared to the level of acceptable change (LAC) of 5.0 percent. The CALPUFF visibility modeling results for the MTB are provided in Table 7-9. The visibility impact is less than 5 percent of modeling threshold for every modeled year and scenario, with a highest predicted change of 1.53 percent (natural gas use). Because the predicted visibility impacts are all well below the LAC, the Project is not expected to have any noticeable effect on visibility and no further analyses were conducted.

Table 7-9
Mt. Baker Wilderness Area Visibility Analysis Results

	Maximum 98th Percentile Change in Light Extinction			
	Worst-Case Natural Gas Turbine Scenario		Worst-Case Distillate Turbine Scenario	
Year	Percent Change	Julian CALPOST-printed Day	Percent Change	Julian CALPOST-printed Day
2003	2.05	249	1.71	256
2004	2.11	196	1.72	196
2005	1.52	212	1.36	212

Note: CALPUFF v5.8 uses the hour-ending method (the hour between 1:00 AM and 2:00AM is labeled as hour 2). CALPUFF numbers the hours 0 to 23, but the 24-hour averaging period should be hour 1 to 24 so that all hours are during the same day. The ending hour of a 24-hour averaging period is not 24:00 but 0:00 of the next day. The Julian CALPOST-printed day represents the ending hour (0:00) of the next day. The actual date for the 24-hour averaged light extinction value represents the previous day.

7.3.6 Total Nitrogen and Sulfur Deposition Analysis

CALPUFF was also used to evaluate the potential for N and S deposition. The total deposition rates for each pollutant were obtained by summing the modeled wet and/or dry deposition rates as follows:

- The deposition of N is the sum of nitrogen contributed by wet and dry fluxes of HNO_3, NO_3, ammonium sulfate ($(NH_4)_2SO_4$), and ammonium nitrate (NH_4NO_3) and the dry flux of NO_x.
- For S deposition, the wet and dry fluxes of SO_2 and SO_4 are calculated, normalized by the molecular weight of sulfur, and expressed as total S.

The total modeled N and S deposition rates were compared to the NPS/FWS Deposition Analysis Threshold (DAT) for western states. The DAT for N and S are each 0.005 kilogram per hectare per year (kg/ha-yr), or 1.59E-11 g/m^2-s.

The CALPUFF deposition modeling results for the MTB are provided in Table 7-10. The deposition rates for N and S are both well below the applicable DAT. The highest predicted rates are 1.95E-12 g/m^2-s for N and 1.023E-12 g/m^2-s for S (both for distillate use). Because the predicted deposition rates are all well below the DAT, the Project is not expected to have a significant effect on either terrestrial resources, such as soil and vegetation, or aquatic resources, and no further analyses were conducted.

Table 7-10
Mt. Baker Wilderness Area Deposition Analysis Results

	Maximum Deposition Rate (g/m^2-s)			
	Worst-Case Natural Gas Turbine Scenario		Worst-Case Distillate Turbine Scenario	
Year	Nitrogen	Sulfur	Nitrogen	Sulfur
2003	1.40E-12	8.70E-13	1.58E-12	8.77E-13
2004	1.72E-12	1.016E-12	1.95E-12	1.023E-12
2005	1.24E-12	6.53E-13	1.40E-12	6.57E-13

7.4 GROWTH IMPACT ANALYSIS

PSE Fredonia facility is located at 13085 Ball Road near Mount Vernon, Skagit County, Washington. According to 2009 census data, Skagit County experienced a total population growth rate of 16.1 percent between 2000 and 2009. Expansion of the FGS does not cause growth, but provides some of its power to the community it serves in Skagit County.

The construction of the Project is expected to begin in 2013 and should take approximately 18 months to complete. The completion of the project will require approximately 200 temporary construction related jobs. It is also expected that the expanded facility will create two to four additional permanent jobs. It is anticipated that the municipal and residential services currently provided in the surrounding communities will be adequate to support the proposed Project; therefore, potential negative impacts on local air quality and Class I area air quality associated with municipal and residential growth are not anticipated.

8.1 INTRODUCTION

As discussed in Section 4.5, demonstration must be made to show that increases in TAP emissions are sufficiently low to protect human health. Per WAC 173-460-080, a 1st Tier Review is made to show that potential impacts meet ASILs for each identified TAP, demonstrated either by meeting the SQER or by dispersion modeling. Table 3-6 shows the estimated TAP emissions for the Project, and includes the SQER and ASIL for each emitted pollutant. As described in Section 3.4, there are 27 TAPs that exceed their specific SQER and require additional analysis. These TAP emissions are shown in bold in Table 3-6, and include the following: 1,3-Butadiene, Acetaldehyde, Acrolein, Ammonia, Arsenic, Benz(a)anthracene, Benzene, Benzo(a)pyrene, Benzo(b)fluorathene, Benzo(k)fluoranthene, Beryllium, Cadmium, Carbon Monoxide, Chromium(VI), Dibenz(a,h)anthracene, Diesel Engine Exhaust Particulate, Ethylbenzene, Formaldehyde, Hydrogen Chloride, Indeno(1,2,3-cd)pyrene, Manganese, Naphthalene, Nitrogen Dioxide, Propylene Oxide, Sulfur Dioxide, Sulfuric Acid, and Vinyl Chloride.

8.2 MODEL SETUP

The TAP impact assessment methodology essentially follows that of the criteria pollutant analyses, as described in Section 6 above. Emissions and stack parameters for each turbine option are developed for the ASIL averaging periods (1-, 24-, or annual averages). The modeling emissions for the 27 pollutants of concern for impact assessment are shown in Table 8-1, along with the ASIL for each. [Note that the emissions provided in Table 3-6 show *total* emissions, turbine(s) plus generator, whereas Table 8-1 separate the turbine and generator emission rates for modeling.]

The annual average stack parameters are based on annual fuel use and operating load expectations, as with the criteria pollutant analyses. The worst-case short-term (1- and 24-hour) stack parameters for each averaging period are taken from the results of the model load check analyses, shown in Table 3-3 (and discussed further in Section 6.3). The 1-hr values use the worst-case NO_x impact values for each turbine option, as this is the only pollutant that requires a 1-hr ASIL evaluation, and the emissions for this TAP are based on the vendor data. The 24-hr parameters use the worst-case PM impact values (for each turbine option); these stack parameters were used for the 24-hr PM_{10} and $PM_{2.5}$ impact analyses. Because the TAP emissions are based on fuel usage, the PM impact values for the load check analyses are more applicable as a fuel-based emission factor (more applicable than NO_x or CO, which are more combustion-derived, and more applicable than SO_2 impact values, which are skewed by the use of ULSD). Table 8-2 shows the modeled stack parameters for each turbine option and averaging period. The emergency generator stack parameters are also provided in this table. All other model setup, including meteorological data, building downwash, and receptor grids, used in the TAP analyses are consistent with those used in the criteria pollutant analyses.

8.3 ASIL COMPLIANCE DEMONSTRATION

The modeling analyses were completed for each turbine option and five years of meteorological data. The results of the analyses are shown in Table 8-3. All impacts are shown to be below the ASIL for each TAP identified. Therefore, the Project meets the Tier 1 review for TAPs, and no further analysis is required.

Table 8-1
Estimated TAP Emissions for Tier I Impact Assessment

Common Name	Washington State SQERs		Maximum Emission Rate (lb/hr)				
	Average Period	SQER (lb/average period)	GE 7FA.05	GE 7FA.04	Siemens SGT6-5000F4	GE LMS100 (2 Units)	Emerg. Generator
1,3-Butadiene	year	1.13	1.43E-03	1.28E-03	1.37E-03	5.62E-04	0.00E+00
Acetaldehyde	year	71	2.52E-01	2.14E-01	2.50E-01	1.31E-01	4.63E-06
Acrolein	24-hr	0.00789	1.55E-01	1.32E-01	1.54E-01	6.22E-02	4.61E-05
Ammonia	24-hr	9.31	3.20E+01	2.87E+01	3.05E+01	1.24E+01	0.00E+00
Arsenic&Inorg.Arsenic Cmpds	year	0.0581	1.69E-04	1.52E-04	1.61E-04	6.53E-05	0.00E+00
Benz[a]anthracene	year	1.74	2.56E-04	2.27E-04	2.47E-04	1.08E-04	1.14E-07
Benzene	year	6.62	3.06E-02	2.64E-02	3.01E-02	1.50E-02	1.43E-04
Benzo[a]pyrene	year	0.174	2.35E-04	2.09E-04	2.26E-04	9.70E-05	4.72E-08
Benzo[b]fluoranthene	year	1.74	2.23E-04	1.99E-04	2.14E-04	9.08E-05	2.04E-07
Benzo[k]fluoranthene	year	1.74	2.23E-04	1.99E-04	2.14E-04	9.07E-05	4.00E-08
Beryllium & Compounds	year	0.08	8.51E-05	7.64E-05	8.12E-05	3.29E-05	0.00E+00
Cadmium & Compounds	year	0.0457	2.21E-04	1.98E-04	2.11E-04	8.55E-05	0.00E+00
Carbon monoxide	1-hr	50.4	5.37E+02	5.36E+02	2.17E+03	5.34E+01	1.06E+00
Chromium(VI)	year	0.00128	1.02E-05	9.14E-06	9.72E-06	3.94E-06	0.00E+00
Dibenz[a,h]anthracene	year	0.16	2.56E-04	2.27E-04	2.47E-04	1.08E-04	6.36E-08
Diesel Eng.Exh,Particulate	year	0.639	0.00E+00	0.00E+00	0.00E+00	0.00E+00	3.34E-03
Ethylbenzene	year	76.8	2.81E-02	2.39E-02	2.79E-02	1.46E-02	0.00E+00
Formaldehyde	year	32	2.05E-01	1.76E-01	2.03E-01	1.03E-01	1.45E-05
Hydrogen Chloride	24-hr	1.18	1.39E+00	1.25E+00	1.33E+00	5.39E-01	0.00E+00
Indeno[1,2,3-cd]pyrene	year	1.74	2.56E-04	2.27E-04	2.47E-04	1.08E-04	7.60E-08
Manganese & Cmpds	24-hr	0.00526	2.32E-01	2.08E-01	2.21E-01	8.95E-02	0.00E+00
Naphthalene	year	5.64	2.11E-02	1.87E-02	2.03E-02	8.68E-03	2.39E-05
Nitrogen dioxide	1-hr	1.03	2.34E+02	2.33E+02	2.38E+02	7.18E+01	7.65E+00
Propylene oxide	year	51.8	2.89E-02	2.46E-02	2.87E-02	1.50E-02	0.00E+00
Sulfur dioxide	1-hr	1.45	1.65E+01	1.62E+01	1.74E+01	8.34E+00	9.76E-03
Sulfuric Acid	24-hr	0.131	2.20E+01	2.52E+01	2.30E+01	8.73E+00	9.76E-03
Vinyl Chloride	year	2.46	4.55E-03	4.08E-03	4.34E-03	1.76E-03	0.00E+00

Table 8-2
TAP Analysis – Worst-Case Operating Stack Parameters

Averaging Period	Turbine Stack Parameters				Scenario Description
	Height (ft)	Temperature (°F)	Velocity (fps)	Diameter (ft)	
GE 7FA5					
Annual	145	800	120	23	All loads and fuel based on predicted use; 51°F
1-hr (NO_2, CO)	145	800	124	23	Distillate; 100% load; 7°F
1-hr (SO_2)	145	800	132	23	Natural Gas; 100% load; 7°F
24-hr	145	799	87	23	Distillate; 50% load; 7°F
GE 7FA4					
Annual	145	800	127	21	All loads and fuel based on predicted use; 51°F
1-hr	145	800	135	21	Distillate (NO_2, CO), Natural Gas (SO_2); 100% load; 7°F
24-hr	145	799	102	21	Distillate; 50% load; 7°F
Siemens SGT6-5000F4					
Annual	145	800	118	23	All loads and fuel based on predicted use; 51°F
1-hr (NO_2)	145	800	126	23	Distillate; 100% load; 7°F
1-hr (CO)	145	799	103	23	Distillate; 75% load; 7°F
1-hr (SO_2)	145	800	130	23	Natural Gas; 100% load; 7°F
24-hr	145	799	95	23	Distillate; 50% load; 88°F
GE LMS100					
Annual	110	777	127	12	All loads and fuel based on predicted use; 51°F
1-hr (NO_2)	110	786	136	12	Distillate; 100% load; 51°F
1-hr (CO)	110	737	134	12	Natural Gas; 100% load; 7°F
1-hr (SO_2)	110	769	136	12	Natural Gas; 100% load; 51°F
24-hr	110	800	113	12	Distillate; 75% load; 88°F
Emergency Generator					
All	50	994	146	0.833	--

Table 8-3
Maximum Predicted TAP Impacts

Common Name	Washington State ASILs		Total Modeled Impacts by Turbine Option (μg/m³)			
	Average Period	ASIL (μg/m³)	GE 7FA.05	GE 7FA.04	Siemens SGT6-5000F4	GE LMS100 (2 Units)
1,3-Butadiene	year	0.00588	< 0.00001	< 0.00001	< 0.00001	< 0.00001
Acetaldehyde	year	0.37	0.00007	0.00007	0.00007	0.00044
Acrolein	24-hr	0.06	0.00170	0.00149	0.00150	0.00535
Ammonia	24-hr	70.8	0.35077	0.32221	0.29659	1.06406
Arsenic&Inorg.Arsenic Cmpds	year	0.000303	< 0.00001	< 0.00001	< 0.00001	< 0.00001
Benz[a]anthracene	year	0.00909	< 0.00001	< 0.00001	< 0.00001	< 0.00001
Benzene	year	0.0345	0.00023	0.00023	0.00015	0.00014
Benzo[a]pyrene	year	0.000909	< 0.00001	< 0.00001	< 0.00001	< 0.00001
Benzo[b]fluoranthene	year	0.00909	< 0.00001	< 0.00001	< 0.00001	< 0.00001
Benzo[k]fluoranthene	year	0.00909	< 0.00001	< 0.00001	< 0.00001	< 0.00001
Beryllium & Compounds	year	0.000417	< 0.00001	< 0.00001	< 0.00001	< 0.00001
Cadmium & Compounds	year	0.000238	< 0.00001	< 0.00001	< 0.00001	< 0.00001
Carbon monoxide	1-hr	23000	24.79	27.23	115.90	15.98
Chromium(VI)	year	0.00000667	< 0.0000001	< 0.0000001	< 0.0000001	< 0.0000001
Dibenz[a,h]anthracene	year	0.000833	< 0.00001	< 0.00001	< 0.00001	< 0.00001
Diesel Eng. Exh., Particulate	year	0.00333	0.00296	0.00296	0.00185	0.00163
Ethylbenzene	year	0.4	0.00001	0.00001	0.00001	0.00005
Formaldehyde	year	0.167	0.00005	0.00006	0.00005	0.00035
Hydrogen Chloride	24-hr	9	0.01524	0.01403	0.01293	0.04625
Indeno[1,2,3-cd]pyrene	year	0.00909	< 0.00001	< 0.00001	< 0.00001	< 0.00001
Manganese & Compounds	24-hr	0.04	0.00254	0.00234	0.00215	0.00768
Naphthalene	year	0.0294	0.00004	0.00004	0.00003	0.00003
Nitrogen dioxide	1-hr	470	172.92	172.91	178.01	98.40
Propylene oxide	year	0.27	0.00001	0.00001	0.00001	0.00005
Sulfur dioxide	1-hr	660	0.70083	0.81701	0.75025	2.38361
Sulfuric Acid	24-hr	1	0.24196	0.28373	0.22457	0.75214
Vinyl Chloride	year	0.0128	< 0.00001	< 0.00001	< 0.00001	0.00001

9.1 INTRODUCTION

The State of Washington has adopted rules governing GHG emissions from new and modified fossil-fueled power plants (WAC 173-407). Part I of these rules addresses GHG emission mitigation requirements, and Part II includes an EPS for baseload power plants including capture/sequestration requirements that apply to baseload power plants that do not meet the EPS. Part I requirements apply to the proposed Project and are addressed in this permit application section.

Part II requirements do not apply to the Project because it is not a baseload power plant (i.e., the Project will have an enforceable annualized plant capacity factor of less than 60 percent). PSE proposes to include annual fuel use restrictions in the Project's air permits to limit the annual capacity factor to below a capacity factor of 60 percent. Although Part II does not apply to the Project, it is important to note that each of the Project's four proposed high-efficiency simple cycle gas turbine options are expected to be very close to the baseload EPS. Estimated turbine efficiencies (lb CO_2e/MW-hr) are provided for each proposed turbine option in Section 5.3.4.1.3.

9.2 MITIGATION COMPLIANCE

Statutory CO_2 mitigation requirements in Part I of the rule apply to new fossil-fueled thermal electric generating facilities with a generating capacity greater than 25 MW but less than 350 MW for which an order of approval application is submitted after July 1, 2004. The Project's proposed generating capacity falls within this range.

9.2.1 Mitigation Emission Calculations

The first applicable Part I requirement is to calculate total CO_2 emissions to be mitigated by following the four calculation steps specified in WAC 173-407-050. Table 9-1 shows the summary of these emissions and mitigation requirements. Detailed calculations are provided in Attachment F for each of the Project's four proposed turbine options. These calculations are based on the preliminary engineering data and operating projections provided in Attachment A. The calculations will be updated and submitted to Ecology prior to construction, after detailed engineering has been conducted, a combustion turbine technology has been selected, and vendor-guaranteed generating capacity has been established. Presumably, final mitigation requirements will be established with Ecology at that time.

Please note that CO_2 emission calculations in Table 9-1 (and Attachment F) are based on engineering assumptions, EPA AP-42 emission factors, and formulae that are dictated by WAC 173-407-050. Due to differences in operating assumptions and required emission calculation methodologies, Attachment F results are not directly comparable to estimates of actual annual GHG emissions that are provided in Section 5.3.4 and the emission summaries shown in Attachment A of this permit application.

Table 9-1
Carbon Dioxide Emissions Mitigation

	GE 7FA.05	GE 7FA.04	Siemens SGT6-5000F4	GE LMS100 (2 Units)
Step 1 -- Annual CO_2 Emissions				
($Tons_{metric}$/yr)	289,687	253,265	280,388	317,039
Step 2 -- 30-Year CO_2 Emissions to Mitigate				
($Tons_{metric}$)	5,214,370	4,558,772	5,046,991	5,706,710
Step 3 -- Cogen Credit				
	N/A	N/A	N/A	N/A
Step 4 -- Mitigation Quantity				
($Tons_{metric}$)	1,042,874	911,754	1,009,398	1,141,342
Third Party Mitigation Plan*				
Mitigation Cost @ \$1.60/Ton_{metric}	$1,668,599	$ 1,458,807	$ 1,615,037	$1,826,147

*Payment to third party (e.g., Oregon Energy Trust) due as a lump sum due 120 days after start of operation or divided into five annual payments. The initial $1.60 fee is set by rule, but may be subject to future change. If the 5 year payment option is chosen, each yearly payment will be based on then current fee.

9.2.2 Mitigation Plan

WAC 173-407-060 offers three plan options to achieve mitigation of a power plant's CO_2 emissions:

- Payment to a third party to provide mitigation;
- Direct purchase of permanent carbon credits; or
- Investment in applicant-controlled mitigation projects.

Selecting the first option under WAC 173-407-060(3), PSE proposes to pay the mitigation rate of \$1.60 per metric ton of CO_2 to a third party, such as the Oregon Climate Trust, in five equal annual installments beginning within 120 days after the start of commercial operation of the Project. The total estimated payments for each proposed turbine option are shown in Table 9-1. Preliminary calculations for total fee and annual payment amounts are also provided in Attachment F.

This permit application section and Attachment F serve as PSE's mitigation option statement required by WAC 173-407-070(1). Further documentation showing how the requirements will be satisfied will be provided to Ecology and NWCAA prior to issuance of an order of approval, as required by WAC 173-407-070(2).